

Municipal Aggregation In Illinois:
An Estimate of the Potential Costs and Savings from Municipal
Aggregation for Selected Illinois Communities

A Report To The Illinois General Assembly

Prepared By The Illinois Commerce Commission

With Assistance From
Center For Neighborhood Technology/
Community Energy Cooperative

Executive Summary

This report addresses the potential benefits of municipal aggregation of retail electric customers as a means for customers to benefit from the Electric Service Customer Choice and Rate Relief Law of 1997 (Public Act 90-561), referred to in this report as the Customer Choice Law. This report was authorized by the General Assembly on June 26, 2002, in Public Act 92-0585.

Municipal aggregation is a process whereby a municipality, county, township, or other form of local government, acts on behalf of all or a part of its constituents in procuring their electric supply, either directly or via a third party supplier. Providing the means to aggregate customers at a reasonable cost is critical to achieving the benefits of municipal aggregation. The Illinois Commerce Commission (“Commission”), with the assistance of the Center for Neighborhood Technology (“CNT”), has undertaken this study to examine the potential benefits of municipal aggregation.

Calculations of cost estimates in the report do not include all of the costs of doing business as an aggregator or Retail Electric Supplier¹ (“RES”), but the estimates provide an idea of potential mark-ups available to an aggregator or RES in conducting business. The higher the actual costs of doing business are for a RES, the lower are potential customer savings.

By aggregating large customer groups and incurring reduced customer acquisition costs, municipal aggregation may provide benefits to customers through lower cost bulk power acquisition. Estimating costs under bundled rates versus aggregated rates, from 1999 through 2002, for six communities in the Commonwealth Edison Company (“ComEd”) service territory, suggests that savings may exist under municipal aggregation. In total, for the six communities over the four-year period, savings are estimated at about 21% of bundled rates. The estimates include a scenario for a 10% load reduction in the summer months, which slightly increases the estimated savings for the four-year period.

¹ A retail electric supplier includes an alternative retail electric supplier or “ARES”, as the term ARES is defined in Section 16-102 of the Customer Choice Law, and an electric utility that provides electric power and energy to one or more retail customers located outside its service area. The term RES is employed because electric utilities in Illinois are excluded from the Customer Choice Law’s definition of an ARES and are not required to be certified as an ARES when they serve customers outside their utility service area. However, Section 16-116(a) of the Customer Choice Law provides that an electric utility serving retail customers outside their service area must do so within the terms and conditions of the delivery service tariffs in effect where the retail customer is located. The terms and conditions of each electric utility’s delivery service tariffs include the requirement that a RES obtain the same authorization to switch a customer as required by Section 16-115A(b) of the Customer Choice Law, and as applicable to an ARES. Thus, the term RES is used throughout this report to include both utility and non-utility retail electric suppliers, and the customer switching provisions of the Customer Choice Law are applicable to both.

Although the savings estimates appear substantial, there is no guarantee that any community will achieve this level of savings in 2007 or beyond when the mandatory transition period and mandatory retail rate freeze expire. Since transition charges are applicable to customers in ComEd's service area until 2007, any aggregation program implemented prior to 2007 would see lower savings than the estimates in this report and most likely more consistent with the mitigation factors provided for in the Customer Choice Law. However, savings may differ from mitigation factors due to the method of calculating transition charges. Transition charges are calculated at a specific time during the year, and for a set of expected market prices for power at that time, but actual market prices for an alternative supplier will differ over that time period. To the extent that actual market values are lower (higher) than those set forth in the transition charge calculation, then actual savings may exceed (be less than) the mitigation factor. The report applies transition charges to 2002 usage and the resulting savings range from 0.55% to 15.59% by community. By including transition charges for 2002, overall savings for that year decrease to 7.44% for all communities.

The savings estimates have limitations that should caution anyone from drawing general conclusions about their likelihood of occurrence because the savings calculations compare historical wholesale power prices to ComEd's rates under bundled service. ComEd's bundled rates are based upon historic costs for generation plants it no longer owns. Thus, the savings results are more a reflection of ComEd's historic generation costs compared to recent wholesale power costs. From the end of 2006, ComEd's rates will reflect its market purchases in some manner to be determined, but both ComEd and a municipal aggregator will be purchasers of large blocks of power in the same market. It is unlikely that a municipal aggregator will consistently be able to purchase power in the same market as ComEd at rates that are significantly lower than ComEd pays.

This report does not attempt to forecast wholesale power prices, which are volatile, and, depending on their movement, could erode all savings, and it does not address the type of market structure that will exist in 2007 and beyond. The dangers from price spikes and volatility for a municipal aggregator are illustrated to some degree in the cost and savings estimates for 1999, a year with warmer than normal summer weather and higher power supply costs. The costs and savings estimates for 1999 provided in Table 3 of this report show that total costs increased by 7.24% for the market aggregation purchases. This increase in costs was off-set by savings in the remaining years, but, if volatility and price spikes are not properly managed by an aggregator via financial derivatives, fixed price contracts, or other means, all of which have a cost that is not included in these estimates, then potential savings could be further eroded.

Notwithstanding the previous comments regarding the savings estimates, it is worthwhile to further investigate the implementation of municipal aggregation because there are no RESs serving residential customers in Illinois, and no ARES are certified to serve residential customers. Residential customers have no alternatives for power supply other than their utility. The RES' lack of interest in serving the residential market may be explained in part by the higher cost of acquiring residential customers, providing customer service, supplying power, and billing customers, all relative to the same costs associated with large industrial customers when

compared to large-customer loads. To the extent that municipal aggregation offers suppliers an opportunity to serve the market in a cost-effective manner, it may offer a realistic option for residential customers to achieve savings on power costs under the Customer Choice Law.

Municipal aggregation, depending on the method employed, can lower customer acquisition costs because the municipality, through its ability to make decisions on behalf of a pre-existing group of customers, appears to be uniquely situated to aggregate large blocks of customers at minimal cost. Municipal aggregation has been implemented in other states, and it appears that one particular form of municipal aggregation, the opt-out method that has been implemented in Ohio, has delivered savings to residential customers and has high participation.

This report focuses on three methods of municipal aggregation: (1) opt-in, (2) opt-out and (3) all-in. All three of these methods require a public decision for the municipality to become an aggregator such as a general vote, a referendum, or a city council decision. Beyond the public decision, under the opt-in method, each resident and business of the municipality must provide express consent (presumably in writing) to participate. By way of contrast, under the opt-out method, a resident or business that does not choose to participate must express (again, presumably in writing) an intent not to participate. Under the all-in method, all residents become part of the aggregation with no opt-out provision. Of the three methods of municipal aggregation, the opt-out and all-in methods minimize customer acquisition costs compared to the opt-in method. However, they also go beyond what is permitted for a private firm under the Customer Choice Law, and thus the need for statutory change if municipal aggregation is to be implemented using these methods.

Municipal aggregation, to the extent it encourages new suppliers to enter the market, may promote the use of real time pricing and technologies that enhance energy efficiency. It is unclear whether implementation costs of such programs permit them to be cost effective, but the larger the aggregation program, then the less prohibitive are such costs for individual customers.

As described in Section II of this report, the Customer Choice Law contains some brief references to the possibility of aggregation of customer demand. However, based upon the experience of other states, there appears to be a need for more enabling language in the law to allow for successful municipal aggregations. For example, requiring that an aggregator become an ARES appears to be a barrier to municipal aggregation because of certain requirements set forth in sections 16-115 and 16-115A of the Customer Choice Law.

Section 16-115A(b) of the Customer Choice Law appears to preclude the opt-out and all-in methods of municipal aggregation because it requires an ARES to obtain authorization prior to switching a customer in a form or manner approved by the Commission and consistent with Section 2EE of the Consumer Fraud and Deceptive Business Practice Act. This requirement is satisfied only by written authorization from the customer to switch suppliers. If a municipal aggregator must become an ARES, then the savings on customer acquisition costs from the opt-out and all-in methods may well disappear. If the Commission's proposed rules (now in second notice period) for the internet enrollment of electric customers, 83 Illinois Administrative Code

Part 453, are finalized, then this ARES requirement may be somewhat less problematic.² However, an electronic signature is still required of each individual customer under the proposed internet enrollment rules and so the proposed internet enrollment rules do not provide for group decisions by a municipality or other entity to aggregate its residents/customers.

Other potential barriers to municipal aggregation include the lack of institutions, regulations and procedures at both the state and local level to implement municipal aggregation programs, the lack of hourly load data at the distribution level for all utilities, and the lack of transparency in the wholesale power market for price discovery.

The Illinois Commerce Commission makes the following recommendations to further explore and implement municipal aggregation.

- For Illinois municipalities to take advantage of the most efficient forms of municipal aggregation, opt-out and all-in aggregation, current statutory provisions must be refined. Provisions to explicitly authorize opt-out and all-in aggregation could include a framework for municipalities to authorize aggregation efforts. Additionally, the consumer switching provisions in the Customer Choice Law would need to be updated to allow municipalities to act on behalf of their residents and businesses that choose to participate.
- Further study of the actions necessary to develop the legal, institutional, and technical capacity for Illinois communities to develop municipal aggregations is needed. The General Assembly and the Governor may wish to consider the appointment of a Task Force to fulfill this need. The report of this Task Force should be submitted within eighteen months after its formation in order to expedite any further changes that may need to be made prior to the end of the transition period.

² Docket No. 02-0290, Order pp. 7-8.

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I. Introduction

This report addresses the potential benefits of municipal aggregation of retail electric customers as a means for customers to benefit from the Electric Service Customer Choice and Rate Relief Law of 1997 (P.A. 90-561, effective December 16, 1997), referred to in this report as the Customer Choice Law. The report was authorized by the General Assembly on June 26, 2002, in Public Act 92-0585. Municipal aggregation is a process whereby a municipality, county, township, or other form of local government, acts on behalf of all or a part of its constituents in procuring their electric supply, either directly or via a third party supplier. Analysis of six communities in Illinois, served by ComEd, suggests that the potential exists for these communities to lower the cost of their electric power below present utility rates. Providing means to aggregate customers at a reasonable cost is critical to municipal aggregation achieving these benefits. The Commission, with the assistance of the CNT, has undertaken this study to examine the potential benefits of municipal aggregation.

The Customer Choice Law has resulted in many changes to the structure of the electric industry in Illinois. Although electric utilities have benefited from a variety of provisions in the Customer Choice Law, commercial and industrial (“C&I”) customers have benefited from the rate freeze and residential customers have benefited from mandated rate reductions, many stakeholders are concerned about the ongoing development of retail competition in Illinois. For example, residential customers are permitted to choose their supplier, but there are no RESs serving residential customers in Illinois and there are no ARES certified to serve Illinois residential customers. In short, at this time, residential customers have no alternative supply options to their utility.

Open-market legislation in Illinois and other states envisioned small customers purchasing power through commercial aggregations of consumers with enough collective buying power to gain access to competitively priced electricity at rates lower than customers previously paid under regulated rates. Municipal aggregation is an alternative to aggregation by commercial suppliers. By having a community decide as a group to obtain alternative electric supply, the cost of aggregating customers can be lowered, increasing the feasibility of small customer electric choice.

Aggregation of customers can take many forms. In fact, traditional utility service is an example of customer aggregation: utilities charge tariff rates based on customer class aggregations, e.g., residential, commercial, and industrial classes. In this manner, utilities have aggregated most of the energy users in the country based on their service territories. Restructuring of the electric industry has introduced a number of new types of aggregation into the marketplace. Aggregators can act as buying agents for customers or can procure, generate, or even distribute electricity to aggregation members. Aggregations can be pre-existing organizations, such as trade associations or municipalities, which may or may not have experience in the energy field, or aggregations can be new entities formed specifically for energy brokering or sales.

Aggregation may be beneficial for customers, but cannot, in and of itself, provide lower cost electric supply. Whether lower cost supply can be provided depends on many factors,

including the existence of a competitive wholesale market for supply and non-discriminatory access to the transmission grid for alternative suppliers. This report does not address those factors. However, municipal aggregation, by lowering entry costs for suppliers, may facilitate some of the benefits intended by the Customer Choice Law. Those benefits include, but are not limited to, lower power costs, greater energy efficiency and environmental protection, and customer access to new technologies.

Participation in the electric market by a municipality is not without risk. Electric markets are volatile and any municipality contemplating participation should carefully assess those risks to ensure that it understands the terms and conditions of any power contracts it enters into to supply its citizens. The results of poor contracting could overwhelm the potential benefits of municipal aggregation.

II. The Policy Context

A. Electric Restructuring Nationwide and in Illinois

State government actions to restructure the electric power industry began in the mid-1990s with the goals of greater efficiency in generation of electricity and lower costs for consumers. However, state governments have more hurdles before them to transform electric utility monopolies into competitive markets, and those goals remain elusive. Nineteen states, with nearly 60% of the nation's population, have enacted electric industry restructuring laws since 1996. However, competition in the mass market for electric service has failed to take hold, with the possible exception of Ohio where the restructuring law encourages municipal aggregation.

Illinois' Customer Choice Law phased in electric provider choice, first for large industrial users, then for smaller commercial and industrial users, and finally for residential users in May of 2002. At the time of this report, no provider has registered to serve the residential market, and competition, where it exists, is largely confined to the industrial and commercial markets in ComEd's service area. With old institutions being dismantled and new market-organizing entities nonexistent, the future for residential and small business customers in the open market is uncertain.

Several factors contribute to the lack of supplier interest for residential customers: 1) residential customers are costly to serve in terms of acquisition, billing, and customer service; 2) residential customers' poor load profile increases the generation cost to serve them when compared to industrial and commercial customers; 3) residential customers benefit from a mandatory rate reduction of up to as much as 20% in the ComEd Illinois Power ("IP") service territories; 4) residential customers receive a smaller mitigation factor³ (to offset transition

³ The mitigation factor is a reduction to utility transition charges that represents the amount to be attributed to new revenue sources and cost reductions by the electric utility through the end of the period for which transition costs are recovered pursuant to Section 16-108. The mitigation factor reduces the amount of transition charges that a customer pays to the utility when they switch to delivery services, and, as such, it provides an incentive for customers to switch.

charges⁴) than industrial and commercial customers; and 5) residential customers, by law, cannot take service under the Power Purchase Option. Mandatory rate reductions, mitigation factors, transition charges and power purchase options will no longer be impediments to serving residential customers in ComEd's service area at the end of the mandatory transition period (December 31, 2006) and beyond. However, there is a possibility that they could remain for other utilities through December 31, 2008. That is to say, the Customer Choice Law freezes retail rates, with some qualifications set forth in Section 16-111, until the mandatory transition period expires on January 1, 2007. Utilities other than ComEd are allowed to petition the Commission for an extension through December 31, 2008.

The Illinois Energy Policy report, released in February 2002 by the Illinois Energy Cabinet⁵, outlined the challenge to small consumers and communities created by electric restructuring:

After January 2005⁶, when Illinois utilities can adjust retail rates to more accurately reflect the wholesale power prices, small volume and residential customers may be exposed to price volatility. Over the next several years, as we approach the end of the restructuring transition period, it is important that these customers be educated in the potential opportunities and issues they will be facing.

Small usage customers are typically costly to maintain. Their variable load curves make them a much riskier customer for the electric provider. These economic factors tend to bias the competitive market away from small volume customers. Aggregating individual customers and their loads, and investing in specific well-defined combinations of energy efficiency and load management technologies has the potential to provide substantial benefits. These benefits, if realized, will accrue not only to the small volume customer, but also to the community, aggregator, alternative electric provider, and the distribution utility.

Aggregating this class of customer into a cohesive group that understands the energy future and is willing to invest in load shaping technologies is not an easy task. There is little institutional basis for the formation and operation of these groups. However, the community based cooperative approach clearly has the potential to merit further investigation. The concept is being tested as a pilot demonstration that should be supported, monitored, and expanded during the transition period.

⁴ Transition charges may be imposed by a utility when a retail customer switches from utility bundled service to delivery services. The transition charge allows the utility to recover a portion of its historic generation costs from customers who switch to alternative suppliers. The transition charge is an average per kWh rate so its effect on savings will vary depending on the amount of energy each customer uses.

⁵ The Illinois Energy Cabinet consists of the directors of the Department of Commerce and Community Affairs, Department of Natural Resources, Department of Nuclear Safety, Environmental Protection Agency, Department of Agriculture, and the Chairman of the Illinois Commerce Commission.

⁶ In May 2002, the Illinois legislature extended the rate freeze through December 2006.

Illinois has both the time and the opportunity, before January 2005 to:

1. *Educate consumers.*
2. *Demonstrate new concepts and technologies.*
3. *Review and experiment with changes in rates, regulations, and procedures that can change consumer behavior.*
4. *Investigate financing tools that can help implement these new concepts.*⁷

Consistent with the findings of the Illinois Energy Cabinet, Governor George H. Ryan signed into law, on June 26, 2002, Public Act 92-0585, which directed the Illinois Commerce Commission to prepare this report on the value of municipal aggregation of electricity customers.⁸ This report examines that value.

B. Aggregation In The Customer Choice Law

The Customer Choice Law allows aggregation, but more enabling language is necessary to make municipal aggregation fully possible. The key provisions in the Law are:

- Aggregators are included in the definition of ARES. (§16-102) An ARES must obtain a certificate of service authority from the Illinois Commerce Commission. (§16-115)
- Electric utilities shall allow the aggregation of loads that are eligible for delivery services. The electric utility shall allow aggregation for any voluntary grouping of customers, including, without limitation, those having a common agent with contractual authority to purchase electric power and energy and delivery services on behalf of all customers in the grouping. (§16-104(b))⁹

While it appears that the legislative intent is to allow for the aggregation of customers, and authority was given to the ICC for the development of rules and regulations to cover aggregation, a number of practical implementation issues still remain to be resolved. Most significant is the requirement that an aggregator meet all of the law's ARES mandates. In particular, the requirement that a customer must provide written authorization before switching electric supply service from a utility to an ARES prevents a municipality, if it is an ARES under the law, from exercising choice on behalf of its residents and businesses. This requirement extends to all RESs through an electric utility's delivery service tariffs.

Given that the Customer Choice Law does not expressly address municipal aggregation, there could be concerns or confusion regarding the differences between a municipal aggregation and municipal ownership of the utility, as well as the effects of municipal aggregation on municipal franchise fee agreements. In the next sections, the report discusses the main distinction between municipal aggregation and municipal utility service, as well as the effect of municipal aggregation on municipal franchise fee agreements.

C. Municipal Aggregation vs. Municipal Utility Ownership

⁷ Illinois Energy Policy. (pp. 65-66)

⁸ Appendix A contains the full text of the bill.

⁹ The full text of these sections are set forth in Appendix B.

Municipal aggregation is not the same as municipal electric utility ownership. Traditionally, some municipalities have themselves owned and operated the electric utility serving their residents, e.g., the City of Springfield, Illinois. Another example of how municipalities may arrange for power supply for their citizens is that of Chatham, Illinois, which owns no generation but does own the electric power distribution system. Under municipal aggregation, the local government instead solicits bids to serve the electricity load of all users in its jurisdiction. In most cases, the municipality acts as a buying agent or retail seller for its businesses and residents, but the municipality is not involved in the transmission or distribution of electricity. Unlike a municipal utility, the municipal aggregator does not become the provider of last resort for electric customers in its area. The distribution utility (or other entity as specified by law) remains the provider of last resort for certain customer groups, e.g., residential customers in a community that has municipally aggregated. Some customer groups may have options to return to utility service, but those options might not impose a service obligation on the utility. Thus, the main differences between municipal aggregation and municipal utility ownership are that the municipal aggregator neither delivers electricity nor becomes the provider of last resort for its customers (to the extent that the utility remains the provider of last resort.)

D. Municipal Franchise Fees

Numerous municipalities negotiate franchise fee agreements with an electric utility for use of the public right of way and streets for the utility's poles, wires, and substations. Municipal aggregation does not infringe upon the franchise fee agreements between the municipality and the utility because it does not affect ownership or control of electric distribution functions. For example, a municipality that has aggregated may contract with an alternative electricity supplier for customers in its jurisdiction, but the distribution utility continues to deliver that electricity to homes and businesses in the municipality under the existing franchise fee agreement.

III. Hindrances to RES Aggregation

A. Costs to Acquire and Serve Residential Customers

Nothing in the Customer Choice Law prohibits a RES from aggregating residential customers, but, as stated previously in the report, not a single RES provides service to residential customer and no ARES have sought certification in Illinois to serve residential customers. The lack of RESs serving residential customers is due in part to the significant cost of acquiring residential customers. As reported by Nancy Rader and Scott Hempling of the American Public Power Association, the cost of acquiring electricity customers in California, by companies such as Green Mountain and Enron Energy Services, ranged from \$100 to \$600 per customer in marketing and advertising.¹⁰ Even with these major investments in marketing, only 1.7% of California residential electricity customers had switched electricity suppliers by October 2000.¹¹

¹⁰ Rader, Nancy and Hempling, Scott. "Promoting Competitive Electricity Markets through Community Purchasing: The Role of Municipal Aggregation." American Public Power Association, January, 2000, pp. 25-27.

¹¹ California Public Utilities Commission. "Direct Access Service Request Reports." http://www.cpuc.ca.gov/static/industry/electric/electric+markets/direct+access/dasrs_present.htm

Since the Customer Choice Law requires that each customer provide authorization (written permission) to switch suppliers, and delivery services tariffs require the same of all RESs, then each residential customer must be contacted by a RES that intends to aggregate a block of residential customers. Although this provision of the law is beneficial to customers because it prevents unauthorized switching of customers (slamming), it also has the unintended result of limiting RES activity. This provision may become somewhat less problematic for a RES in the future because the Commission has recently approved rules for the provision of internet enrollment of electric customers.¹² However, the internet enrollment rules are not yet in effect and are currently before the Joint Committee on Administrative Rules for second notice. Furthermore, an electronic signature is still required of each individual customer under the proposed internet enrollment rules and so the proposed rules do not provide for group decisions by a municipality or other entity to aggregate its residents/customers. In the Order in that proceeding, the Commission also concluded that it was not legally permissible to use voice recorded authorization from telemarketing calls to authorize customer switching.¹³

A utility's monthly customer charge for a residential customer generally recovers the costs associated with metering, billing, and customer service. This charge represents a much larger share of the average residential customer's monthly bill than for a commercial or industrial customer.

In addition to the high acquisition, metering, billing and customer service costs of serving residential customers relative to those customers' overall electric bills, the load factor ("LF") of residential customers is generally lower than the system average, which results in higher hourly costs for power to serve residential customers as compared to C&I customers. The LF is an expression of the kWh energy usage per kW of demand. While residential demand may be high relative to total system demand during hot summer days, residential customers still do not use as much energy as their C&I counterparts throughout the remainder of the year. The latter implies that for a given MW of generating capacity needed to serve residential peak demand, that capacity is more likely to be idle in non-peak periods for residential customers than for C&I customers. Residential customers' lower utilization of capacity increases the per-MW cost to supply their power. At a higher cost of service in the open market, relative to the bundled tariff, residential customers are not as profitable for a RES to serve as C&I customers.

Low load factors, billing, metering and customer service costs would exist whether a RES aggregated 10,000 or 10 residential customers, but they underscore the importance of lowering customer acquisition costs to promote viable supply options for residential customers. Later in the report is a discussion about how municipal aggregation may promote use of real time pricing and technology that enhances energy efficiency, both of which should improve residential load factors.

B. Mandatory Rate Reductions and Transition Charges

¹² Docket No. 02-0290, Order pp. 7-8, October 23, 2002.

¹³ Order pp. 4-5.

The Customer Choice Law reduced residential base rates by up to 20% during the mandatory transition period for ComEd and IP. (Section 16-111(b)) With such a large rate reduction for a class of customers that are relatively more costly to serve, a RES has less potential margin between wholesale power costs and the utility's bundled rates and would be less likely to be interested in serving residential customers. However, in this context, the 20% residential rate reduction may also clearly be viewed as benefits in lieu of the RES' interest in serving the market.

Electric utilities are allowed to impose transition charges on customers who elect to switch from bundled utility service to utility delivery services. (See Section 16-102, and Section 16-108 of the Customer Choice Law.) However, transition charges erode a significant portion of the potential savings for residential customers from switching suppliers. For this reason also, residential customers may be less attractive to RESs than industrial and commercial customers: the lower residential customer mitigation factor results in higher transition charges and lower margin from which a potential RES could make a profit.

The mitigation factor in Section 16-102(4) of the Customer Choice Law promotes customer supplier switching since it provides for a reduction in utility transition charges. In comparing the mitigation factors applicable to residential customers versus industrial and commercial customers, the mitigation factors for residential customers are somewhat lower than the mitigation factors for nonresidential customers for each period. Mitigation factors are not provided for in the Customer Choice Law beyond 2006. See Table 1 for the mitigation factors by customer class for each period.

Table 1 Mitigation Factors

	Period 1	Period 2	Period 3	Period 4
Mitigation Factors	Through December 31, 2002	Calendars years 2003 & 2004	Calendar Year 2005	Calendar Year 2006
Nonresidential	8%	10%	11%	12%
Residential	6%	7%	8%	10%

C. Power Purchase Option ("PPO")

The Customer Choice Law has a statutory mitigation factor that provides an opportunity for customers to obtain savings during the mandatory transition period, while also providing transition charges to the utility to recover its sunk generation costs. However, concerns about the lack of availability of power on the wholesale market, and the lack of availability of transmission services, resulted in the requirement that utilities offer the PPO. PPO service is available to C&I customers (or their RES if C&I customer PPO rights are assigned to their RES) that would be subject to transition charges. The key feature of the PPO in this context is that the power is provided by the incumbent utility, not by the RES. The PPO provides C&I customers

with delivery service and power and energy from the utility at average price reductions equal to the statutory mitigation factor, less administrative fees. The PPO can reduce a RES' risk by giving a RES an option to continue to meet its contractual obligations to a customer when wholesale prices or transmission limitations would otherwise make meeting such obligations unprofitable. However, the PPO is not available to residential customers and a RES faces the same wholesale power market and transmission system constraints whether its customers are C&I or residential. The lack of the PPO for residential customers may make serving residential customers more risky and less attractive.

Several factors are discussed in this section that appear to make the aggregation of residential customers less attractive to a RES. Of these prohibitive factors, customer acquisition costs and the relatively higher cost to serve residential customers will remain when the retail rate freeze expires in 2007. If municipal aggregation lowers customer acquisition costs, it may provide a jump-start for competitive activity to serve residential customers once the rate freeze expires. If suppliers are able to enter the residential market via municipal aggregation, then it is reasonable to expect that such competitive activity may bring pricing programs and new technologies to customers, e.g., real-time pricing¹⁴, and other energy efficiency technologies. In short, municipal aggregation appears to have a role in promoting the development of retail competition for residential customers in 2007 and beyond.

IV. Role of Municipal Aggregation

A. Participation Choice: Allowing Group Decisions

Municipal aggregation, depending on the type of aggregation employed, differs significantly from aggregation undertaken by a private entity, e.g., a professional or religious organization, in its reliance on individual customer decisions whether to participate in the aggregation program. A private entity not only cannot enforce its decisions on non-members but also is limited by contractual terms and governing laws with respect to its membership. For example, a private organization is not able to unilaterally nullify a member's electric service with the local utility and begin purchasing power for that customer. The private organization can aggregate individuals once they have agreed to participate, but the individual must first decide that the potential benefits warrant participation.

Municipal aggregation represents a change in how participation choices are made because the municipality may be empowered by law to make group decisions for its residents. Thus, the municipal leadership can decide what is best for the group. Favoring group decisions over individual decisions may be warranted for municipal aggregation programs because lower customer acquisition costs and larger blocks of power are critical to achieving the potential benefits from alternative suppliers. According to Rader and Hempling:

¹⁴ Although a form of real-time pricing is available today from the utility, for all customers, there has been little customer participation to date. An aggregator may propose more attractive real-time pricing programs for customers than those programs offered via the utility.

Evidence of the benefits of joint action already exists among large business and institutional consumers, many of who are shopping the retail electricity markets in groups. For a municipal aggregator to provide comparable benefits to the small-customer community, the municipality must be similarly free to act in the marketplace, and it must be able to avoid the high transaction costs of individually signing up each consumer. State laws authorizing municipal aggregation should allow local decision makers the flexibility to determine the most effective ways of enrolling and serving their residents, including the ability to enroll them automatically upon a majority vote of the local legislative body.¹⁵

The ability to aggregate large amounts of load while incurring relatively low acquisition costs is the most attractive aspect of aggregation, and the municipality appears to be ideally situated to lower those acquisition costs over other non-utility aggregators and suppliers.

B. Role of Opt-In, Opt-Out, and All-In Methods of Municipal Aggregation

This report identifies three methods of municipal aggregation: 1) opt-in; 2) opt-out; and 3) all-in. Municipal aggregation may promote the development of retail competition because the municipality, acting as an aggregator, may be able to aggregate a pre-defined block of customers at minimal cost, depending on the method of aggregation that is used. All three of these methods have some type of public decision for the municipality to become an aggregator such as a general vote, a referendum, or a city council decision.

The cost of aggregating customers goes down and the number of customers in the aggregation goes up as one moves from methods 1) to 3). Under the opt-in method, each resident or business of the municipality must provide an expressed consent (presumably in writing) to participate. In contrast, under the opt-out method, a resident who does not wish to participate must indicate their expressed intent (again, presumably in writing) not to participate. Under the all-in method, all residents become part of the aggregation with no opt-out possibility. The all-in method is similar to a municipality's decision to be the sole provider of electric service or water and sewer service to its residents, but it does not require that the municipality acquire generating plants or a transmission and distribution system. In essence, decision makers are faced with the choice of whether the potential benefits of joint action are worth the cost of limiting individual choice and the extent to which it should be limited.

Of the three methods of municipal aggregation, the opt-in method is available now to a RES and to municipalities that become a RES. Since the opt-in method requires positive affirmation from each customer to participate, it is consistent with the sections of the Customer Choice Law that govern ARES behavior and the required customer authorization to switch, as well as the applicable terms and conditions of a utility's delivery service tariffs. No municipality or RES is currently aggregating residential customers in Illinois under the opt-in method. The opt-out and all-in methods go beyond what is permitted for a private firm under the Customer Choice Law; thus the need for statutory change if municipal aggregation is to be implemented using these methods.

¹⁵ Rader and Hempling, p. 4.

V. Ancillary Benefits of Municipal Aggregation

Municipal aggregation that lowers customer acquisition costs and promotes entry of suppliers into the market may also provide additional benefits through this competitive activity in the form of bulk purchasing, real-time pricing, and the use of energy efficient technology. This section will outline some of the key tools that could be utilized by a municipal aggregation.

A. Bulk Purchasing

Purchasing larger blocks of power allows sellers to distribute their fixed costs over greater numbers of consumer units and thus reduces per unit costs to consumers. Costco and other “big box” retailers are perhaps the most obvious example of this trend among retailers. In addition to spreading fixed costs over greater volumes of output, and lower customer acquisition costs, delivery costs associated with power scheduling, energy imbalances and other ancillary transmission services can be reduced if tens of thousands of individual transactions are aggregated into a handful of transactions.

B. Energy Efficiency and Load Management

In addition to lowering per unit bulk power costs, aggregation may contribute to lowering the per customer implementation costs of energy efficiency and load shaping programs. In fact, depending on how supply is procured, e.g., through fixed price contracts, spot market purchases, etc, and the degree to which suppliers offer a variety of products to customers, then energy efficiency and load shaping programs may be aggressively marketed to aggregation customers. The recent study “Community Based Energy Program A Study Of Load Aggregation And Peak Demand Reduction” provides insights into these possibilities. The study states that,

[F]or small volume customers to take advantage of the open access wholesale electric market, they may need to be aggregated into larger consumption groups. However, aggregation alone simply converts a small volume customer, with an unattractive load profile, into a large volume customer with an unattractive load profile. Therefore, the aggregated consumption group should consider implementing technologies that can flatten their load profiles. By accomplishing both the aggregation of the loads and the flattening of the load profile, these small volume customers collectively become much more attractive to both the alternative electric retailer and the local electric Distribution Company.¹⁶

The study profiles a range of technologies and projects that could be available to different customer sectors, including the residential and small commercial sectors. For these two sectors, air conditioning and lighting are the main areas of possible load shaping, and in larger commercial, industrial and institutional settings additional technologies, such as combined heat and power, distributed generation and thermal storage also become options. A summary of the study is contained in Appendix D. The model used for this study will also be used in to

¹⁶ Community Based Energy Program A Study Of Load Aggregation And Peak Demand Reduction, p. 10.

demonstrate how energy efficiency and load management techniques might affect the costs for the communities profiled in the community case studies of this report.

C Real Time Pricing

The actual market price of electricity may vary dramatically over the course of an hour, a day, a month or a season. However, residential and small commercial customers who take service under bundled utility rates have expressed little interest in real-time prices, even though tariffs providing time-differentiated rates are available. As the restructuring of electricity markets continues, suppliers are thought to be more likely to offer attractive time-differentiated products to residential and small commercial customers. To the extent that municipal aggregation promotes the development of retail competition in Illinois, then real-time pricing may be a more prevalent option for residential customers.

Given the right set of tools, power procurement managers for large aggregations of residential and small commercial customers could learn to manage the risks of the market and thus take advantage of the opportunities for lower costs presented by restructuring as envisioned in the Customer Choice Law. According to Eric Hirst and Brendan Kirby in “Retail Load Participation in Competitive Wholesale Electricity Markets,” there are three fundamental benefits, including:

Customers who choose to face the volatility of electricity prices can lower their electricity bills in two ways. First, they provide their own insurance. Second, they can modify electricity usage in response to changing prices, increasing usage during low-price periods and cutting usage during high-price periods.

Retail customers who modify their usage in response to price volatility help lower the size of price spikes. This demand-induced reduction in prices is a powerful way to discipline the market power that some generators would otherwise have when demand is high and supplies are tight. And these price spike reductions benefit all retail customers, not just those who modify their consumption in response to changing prices...

Customers who face real-time prices and respond to those prices provide valuable reliability services to the local control area. Specifically, load reductions at times of high prices (generally caused by tight supplies) provide the same reliability that the same amount of additional generating capacity would.

Finally, strategically timed demand reductions decrease the need to build new generation and transmission facilities. When demand responds to price, system load factors improve, increasing the utilization of existing generation and reducing the need to build new facilities. Deferring such construction may improve environmental quality. Cutting demand at times of high prices may also encourage the retirement of aging and inefficient generating units.¹⁷

¹⁷ Eric Hirst and Brendan Kirby, “Retail Load Participation in Competitive Wholesale Electricity Markets”, pp v – vi.

Although real-time pricing may provide a powerful tool for customers to discipline wholesale market power abuses, and avoid hourly price spikes, by shifting usage to off-peak periods, such hourly demand responses may not be practical for customers who are not accustomed to purchasing electricity in this manner. For example, during the time necessary for customers to learn to alter their usage patterns on an hourly basis, the dollar cost of “mistakes” on behalf of the customer could be dramatic. To insulate themselves from those “mistakes,” many residential and small commercial customers may prefer fixed price contracts for electricity. Until the market becomes competitive and is not subject to the type of manipulation experienced in California, it may not be prudent for a municipality to move quickly toward the reliance upon mandated real-time pricing for customers.

Benefits from real-time pricing do not readily accrue to residential customers simply by the virtue of their participation in a municipal aggregation program. Each customer must have hourly metering devices to receive price signals and adjust usage accordingly. Such equipment can be costly, which may erode the savings resulting from hourly shifts in customer usage. However, the cost of such metering has decreased rapidly over the past several years from over \$1200 per meter in the late-eighties to \$600 in the mid-nineties to about \$150 per meter today and is likely to continue to fall. As utilities unveil other new metering technologies, such as automated meter reading (which can now add several hundred dollars to the cost of even a standard meter), such technology can be phased in. In addition, spreading the cost of metering over the life of the meters, or other financing mechanisms, will mitigate the erosion of savings by the cost of real time meters.

Unacceptable price volatility may be addressed through risk management techniques. Risk management tools long used by large industrial and commercial facilities may be adapted to the scale of residential and small commercial aggregations. Such risk management tools include real time price signals and consumption feedback, strategically targeted efficiency investments, and the use of selected financial instruments to self-insure against extremely high price spikes. The adoption of real-time pricing structures could provide consumers the opportunity to benefit from the variable price of electricity and use savings from times of low cost to invest in efficiency measures to manage usage at times of high cost. A municipality considering aggregation and real-time pricing for its residents must employ due diligence in evaluating risk management tools because the market for derivatives is complex and counter-party default could be financially disastrous for the municipality.

In terms of actual experience with real-time hourly prices, the Community Energy Cooperative analyzed historical hourly energy prices for Northern Illinois from 1999 to 2001 and determined that prices for electricity were quite low in most hours and spiked during hot summer afternoons. The Cooperative also determined that, before any action was taken to manage costs during the price spikes, the inherent savings from a real time price could be in the 10 to 20% range, i.e., potentially \$100 per year off the total electricity bill. The Cooperative’s third finding showed that actions taken to reduce peak demand would further increase those savings and that the cost of those actions could be more than offset by the savings from times of low prices. Actions to reduce peak demand could include both investments in energy efficiency, such as upgrading air conditioning systems, and behavioral changes, such as reducing consumption in

response to a price notification. In conducting this analysis, the Cooperative looked at energy pricing and demand response only: issues of how to calculate and amortize the cost of metering were not included in this phase of their research.¹⁸ This report does not forecast future market prices: it is not prudent to draw a general conclusion that future electricity prices will spike only in a small number of foreseeable hours in the summer because this behavior has been observed over a limited historical period.

D. Renewable Energy

There are additional indirect benefits from aggregation, particularly to the degree that the aggregator might be able to negotiate power source and energy efficiency concessions. Rader and Hempling describe a scenario that demonstrates this case:

Because many local communities are interested in reducing their environmental impacts, these communities are likely to be interested in aggregating their electricity loads at least in part because of the possibility of obtaining power from resources that have lower environmental impacts. Several California cities, including Santa Monica and cities in the San Diego area, are already purchasing renewable energy for their governments' own electricity use. Cities will also be interested in incorporating energy-efficiency efforts into their aggregation programs because: (a) investments in energy efficiency can more than pay for themselves; and (b) energy dollars saved through energy-efficiency programs are dollars that can be spent in the community.

*A municipal aggregator could incorporate community preferences for green resources in a number of ways, such as: (a) the aggregator could require bidders to obtain some or all of their power from renewable energy resources or to provide energy-efficiency services to consumers in the community, or both; (b) the aggregator could acquire energy-efficiency services from a separate provider but incorporate the services into the aggregation program; and (c) the aggregator could give extra scoring points to bidders who provide these types of resources.*¹⁹

The possibility of using aggregation to promote renewable and local energy sources is consistent with the recommendations of the Illinois Energy Cabinet. The state currently has a goal of renewable energy representing 5% of the state's energy portfolio by 2010 and 15% by 2020. For the renewable energy market to develop, there has to be a demand for the product. Since the demand for renewable forms of energy is typically greater from residential customers and governmental mandates, then municipal aggregation, to the extent that it results in increased supplier activity, should promote these goals as well.

¹⁸ For a more detailed discussion of these load reduction programs, see the report, "Community Based Energy Program A Study Of Load Aggregation And Peak Demand Reduction," prepared by the University of Illinois at Chicago/Energy Resources Center, ICF Consulting, the Illinois Department of Natural Resources, and National Economic Research Associates, June 2001. See Appendix D in this report for a summary of the load reduction study.

¹⁹ Rader and Hempling, pp 32-33.

VI. Aggregation in Other States

There are examples of municipal aggregation from several other states, with Ohio undertaking the most developed aggregation experiment. An examination of these examples can provide insight into the possibilities, benefits, and challenges that could face aggregation efforts in Illinois. Listed below are narrative descriptions of other state and local experiences. Listed in Appendix C is a summary chart of these examples, and text of the enabling legislation from each of these states that made municipal aggregation possible.

A. Ohio

Of the states surveyed, Ohio has the greatest number of towns and electricity customers participating in municipal aggregation. Over 100 municipalities, totaling 390,000 individual customers, have taken advantage of the aggregation provisions of Ohio's restructuring law. Ohio permits opt-out aggregation. Customer savings range from 1-15%. In addition, the municipal aggregations offer a greener energy supply portfolios than the average for Ohio.

Municipal aggregation has dramatically increased the energy choices for small customers in Ohio. A 2002 report by the Ohio PUC shows that 85% of the residential electricity customers (436,958 out of 517,563), 50% of commercial (12,375 out of 22,052), and 25% of industrial customers (219 out of 854) who have switched providers, have done so under municipal aggregation.²⁰

The largest municipal aggregator in Ohio, and in the country, is the Northeast Ohio Public Energy Council ("NOPEC"). NOPEC is a coalition of 100 municipalities who have formed an electricity-buying group for electricity consumers in their jurisdictions. As dictated by the Ohio aggregation law, each NOPEC member-community has held a referendum to approve opt-out aggregation. In 2001, NOPEC contracted with Green Mountain Energy to provide electricity that is less expensive and less polluting than the average available in the area.

NOPEC allows municipalities to work together to institute municipal aggregation, thus local governments can share the legal and energy consultant costs for services and expertise that are needed to implement municipal aggregation. This reduction in shared costs enables smaller communities to afford participation.

B. California

California passed a "community choice" law in the fall of 2002 to allow opt-out municipal aggregation. The financial ability of municipalities to participate in aggregation will likely be determined by the size of the exit fees set by the California Public Utilities Commission ("CPUC") for leaving the standard utility service. The CPUC sees the exit fees as necessary to recover the costs of the long-term power contracts that the state entered into during the energy crisis that are now above wholesale market rates for electricity

²⁰ Aggregation activity and customer switching statistics are available on the Internet site of the Ohio Public Utility Commission: <http://www.puc.state.oh.us/ohioutil/MarketMonitoring/marketmonitoring.html>.

Despite the existence of exit fees, aggregation may be still be attractive to some municipalities: California law grants, to municipalities which have enacted aggregation, access to their customers' portion of the state's public goods charge energy efficiency funds. The public goods charge is a fee assessed on utility bills and used to fund energy efficiency and low-income energy assistance programs in the state. Currently, these programs are administered by the state's three investor-owned utilities. Access to these funds may allow municipalities who aggregate to fund demand management programs that customers might otherwise find cost prohibitive

Even before the passage of California's opt-out aggregation law, the city of Palm Springs, California, set up a municipal aggregation using the opt-in aggregation provisions of the California 1996 deregulation law. Palm Springs considered establishing a municipal utility in the mid 1990s, but found that owning and running an entire distribution system was not financially feasible. Instead, the city took advantage of California's 1996 electricity restructuring law. That law also required municipal aggregators to go through the same third party verification steps for switching the service providers of customers as private aggregators, a costly and time-consuming process that proved to be a barrier to the implementation of the aggregation. However, the verification process was removed for municipal aggregators under a 1997 law and Palm Springs was able to move forward towards aggregating the energy users in their community

In 1998, the city created Palm Springs Energy Services and entered into an agreement with First Point Solutions to provide electricity to energy customers in Palm Springs at an initial rate of 10.6 cents per kWh, or at a higher rate if a green energy option was chosen. The terms of the agreement were quite favorable for the city, and included non-electricity benefits for the community, such as non-profit donations and economic development money. Additionally, all marketing expenses were to be paid for by the electricity provider. Finally, the agreement contained a clause that if 25% of the city's energy users, or about 8,000 consumers, did not sign up by January 1999, either the city or the provider could exit the deal with no penalties.²¹

The aggregation did not get the subscription rate the city anticipated, however, and First Point Solutions left the program in early 1999. Palm Springs Energy Services was then taken over by New West Energy, which offered higher prices than the original supplier—2% below Southern California Edison rates, as opposed to around 17% below²²--but ran the program until early 2001. During the California energy crisis, however, New West could no longer beat the standard price offered by Southern California Edison and all of the Palm Springs Energy Services customers transitioned back to Southern California Edison.²³

²¹ Local Government Commission. "Community Aggregation: Palm Springs." Accessed October 28, 2002. <http://www.lgc.org/freepub/energy/case2.html>.

²² Katherine Marks. "When Cities Purchase Power Big Savings Aren't Guaranteed." North County Times. September 17, 2000. <http://www.nctimes.net/news/091700/nnn.html>

²³ "City Shorts: Summary of the Palm Springs City Council Meeting of November 7, 2001." Accessed November 5, 2002. http://www.ci.palm-springs.ca.us/Departments/City_Manager/City_News/City_Shots/City_shorts_11-7.pdf

The results of this experiment are clearly mixed. The initial participation and savings goals were not met, but the participants did experience some savings. As of January 2001, 1,300 customers had signed up with Palm Springs Energy Services and had paid 2% less than Southern California Edison prices for electricity for a total savings of around \$88,000 for the life of the program.²⁴

The early Palm Springs program demonstrated many of the limitations of opt-in municipal aggregation. Under the program's opt-in requirements, each Palm Springs resident had to actively choose to switch to the municipal aggregation, and many did not bother despite sizeable energy savings under the first energy supplier. The cost of marketing to the residents was prohibitive as well, and, in fact, the second provider, New West, was not required by their contract to do any marketing to residents. Thus, even without the dramatic rise in wholesale energy costs, the opt-in provisions of the program had caused it to stagnate. The effect of the wholesale market on Palm Spring's experience should not be ignored, however, for it demonstrates that aggregation needs a fair, competitive and transparent wholesale electricity market in order to succeed.²⁵

C. Rhode Island

Rhode Island passed an opt-out aggregation law in the spring of 2002 with a set of changes to its 1996 restructuring law. No municipality in Rhode Island has made use of this law yet.

D. Massachusetts

The Massachusetts electricity deregulation law of 1997 included opportunities for opt-out municipal aggregation. Based on these provisions, a group of local governments in Massachusetts formed an organization, known as the Cape Light Compact, and set out to buy power for the residents of the Cape Cod region in the late 1990's. The Massachusetts deregulation scheme creates two price categories for residential electricity customers, "standard offer" prices, and "default" prices. Standard offer prices are for electricity provided by the investor-owned utilities and were set by the state to gradually increase until they are phased out in 2005. The default price is the rate set by the state for electricity customers who are new to the area or have left their default electricity provider and then return. The Massachusetts aggregation law dictated that municipal aggregations can only contract for electricity that is lower priced than the standard offer. The regulated standard offer prices for electricity in Massachusetts were lower than the wholesale prices at the time that Cape Light first sought bids for service, and as a result of these price constraints, Cape Light was not able to establish a contract for service until they changed their aggregation model. Cape Light is now a pilot project, and, rather than providing electricity for all residents in the area, it provides electricity for those 45,000 customers in the area who would otherwise be on the default service plan—those who have switched away from the standard offer service or have moved into the area. The default rate is higher than wholesale rates and therefore allows Cape Light to offer these

²⁴ "City Shorts: Summary of the Palm Springs City Council Meeting of January 3, 2001." Accessed November 5, 2002. http://www.ci.palm-springs.ca.us/Departments/City_Manager/City_News/City_Shots/City_shorts_1-3.pdf

²⁵ Rader

customers 11 to 22 percent savings from the default rate along with a number of green energy options.²⁶ Cape Light's innovation in establishing a pilot project for the customers otherwise on the more expensive default rate allows them to gain experience that will ready them for a full scale municipal aggregation program as the standard offer prices are phased out.

As we discuss elsewhere in this document, energy efficiency can be enhanced by municipal aggregation. By procuring electricity for the 45,000 customers, who would otherwise pay the state's default rate, Cape Light is able to offer a number of energy efficiency programs for the members of the aggregation using public benefits funds.

VII. Measuring Municipal Aggregation's Potential Benefits

In this section, estimates of potential savings from aggregation in Illinois are presented. Public Act 92-0585 requires this report to include, "estimates of the potential benefits of municipal aggregation to Illinois electricity customers in at least 5 specific municipal examples comparing their costs under bundled rates and unbundled rates, including real-time prices."²⁷ In preparing this analysis, six communities in ComEd's service territory were selected: De Kalb, Elgin, Evanston, Kankakee, Park Forest, and Woodstock. Initially, a community in a downstate region was selected for this study, but the local utility was unable to produce the substation-level hourly load data necessary for the analysis. The estimates compare the cost to provide power in those communities, under bundled utility service versus aggregation/market service, assuming historical usage from calendar year 2001 and wholesale prices for the years 1999 - 2002. The estimates also compare the cost to provide power in those communities, under bundled utility service versus aggregation/market service, assuming a 10% load reduction in the summer for aggregation/market service and wholesale prices for the years 1999 – 2002. The 10% summer load reduction scenario is an attempt to include the benefits that municipal aggregation may provide through implementation of energy-efficiency technologies and through demand responses from real-time pricing. The cost of interval metering and installation for residential and small commercial customers is included in the total costs for the 10% load reduction scenario, but the 10% reduction is a gross figure, and no attempt is made in this report to allocate the load reduction to specific technologies and pricing programs. The 10% summer load reduction is consistent with models in the study, "Community Based Energy Program A Study Of Load Aggregation And Peak Demand Reduction," prepared by the University of Illinois at Chicago/Energy Resources Center, ICF Consulting, the Illinois Department of Natural Resources, and National Economic Research Associates, June 2001. See Appendix D in this report for a summary of the load reduction study. In order to simplify the calculations, no taxes are included the cost estimates. Also, to be consistent with a post-transition charge environment perspective, no transition charges or decommissioning costs are included

A Difficulties in Calculating Savings Under Municipal Aggregation

It is difficult to calculate a reliable figure for savings under a municipal aggregation program because many of the factors that affect rates (and thus savings) are unknown or likely to

²⁶ Brown

²⁷ See Appendix 1 for the full text of the statute.

change when the retail rate freeze ends in 2007. For example, it is still not known what type of wholesale market structure will exist in 2007, and, as witnessed in California, the structure of the wholesale market will play a significant role in the development of retail competition. One thing that is known about the wholesale market is that electricity prices are extremely volatile and difficult to predict. Prior to restructuring, price volatility was largely explained by extreme weather events or the unexpected outage of a large power plant, but in the restructured market, it is apparent that volatility can be exacerbated by market price manipulation. Given these concerns regarding the uncertainty surrounding market structure and wholesale power prices, the Commission cautions against drawing general conclusions from the savings calculations in this report. These savings calculations are derived from the circumstances of today's market place and it is unknown whether, or to what extent, today's market structure will exist in 2007.

To further illustrate why general conclusions should not be drawn from the savings calculations in the report, consider how ComEd's retail rate for power under bundled service is determined today versus how it will be determined in 2007. In today's bundled retail rate, the generation component reflects ComEd's historical costs of its generation plants. However, ComEd no longer owns the generating plants upon which its bundled retail rate component is based, and, once the mandatory rate freeze expires in 2007, ComEd's bundled rate will most likely be adjusted to reflect ComEd's costs of procuring power in the wholesale market and, consequently, reliance upon the bundled retail rate in this comparison to develop projections for the future is problematic. Since ComEd's current bundled rates are fixed and based on historical costs, opportunities for achieving savings under municipal aggregation are primarily driven by the current state of wholesale power prices versus the bundled rate. Wholesale power prices today are lower than ComEd's bundled rate component and, therefore, savings for the years 1999 – 2002, as set forth on Table 2, appear to be significant. However, in 2007 there could just as easily be little or no savings under a municipal aggregation program, depending on the level of wholesale power prices. Furthermore, in 2007 municipal aggregators and ComEd will be purchasers of large blocks of power in the same market, and it is unlikely that either ComEd or a municipal aggregator will consistently be able to procure power supply at rates significantly less than the other through arm's length transactions. Given the limitations inherent in this analysis, the Commission cautions against drawing general conclusions from the rate comparisons and savings calculations set forth in this report.

B. Data Collection and Methodology

Two data sets were provided by ComEd for this study. The first data set contained aggregate monthly values for each commercial and residential customer class grouped by the city of record for the billing address from January – December 2001. This data is referred to as the "aggregate monthly data." Aggregate monthly data is needed because the transmission substation service areas do not precisely match the geographic boundaries of the municipality: aggregate monthly data assists in calculating the cost to serve a customer class in a municipality.

The second data set contained hourly demand values for transmission substations for the municipalities covered in this study from January - December 2001, and is referred to as "interval data." Interval data is needed because the savings estimates are a comparison of market purchases to bundled rates, and the cost of power in the market varies by hour throughout each

day. To estimate market costs for power, the hourly costs and hourly usage of power in the market must be known.

The ComEd Hourly Energy Price (“HEP”) index, published on the internet, was used to estimate the costs for energy under municipal aggregation. The algorithm in the ComEd HEP tariff changed in March, 2001 to reflect ComEd’s reliance on a Power Purchase Agreement to meet the full requirements of its customer load. HEP prices from the ComEd web site prior to this date have been adjusted to reflect the existing algorithm in the ComEd HEP tariff. As stated in ComEd’s HEP tariff, the tariff reflects HEP hourly prices include a 10% adder. It is unclear whether the 10% adder is reasonable for future consideration, but, for the purposes of this report, it can be viewed as a proxy for a retail supplier’s mark-up to cover its costs. Each HEP value for the year was first multiplied by the corresponding hourly usage provided in the interval data. This resulted in an hourly energy cost value for energy supply during the study period. HEP data for the years 1999, 2000, 2001 and 2002 was utilized in the analysis, with 1999 representing a year with above normal summer weather and above normal wholesale prices for electricity.

The next step was to convert the hourly cost data to comparable monthly values. This was accomplished by calculating the average monthly unit energy cost. The average monthly unit energy cost was applied to the monthly ComEd aggregate consumption to estimate a total monthly cost for energy supply for each month in the years 1999, 2000, 2001, and 2002.

After estimating energy supply costs, the next step was to examine transmission and distribution (“T&D”) costs. ComEd offers a tariff for customers receiving energy supply from alternate suppliers that is designed to cover T&D costs. This tariff is called Retail Customer Distribution service (“RCDS”). RCDS costs are published for residential, commercial, and industrial customers by rate class.

The RCDS rates for residential customers are based on usage (\$/kWh): therefore, it was relatively easy to estimate the residential T&D costs from the monthly aggregate data. C&I RCDS transmission rates are based on usage (\$/kWh) as well, but C&I RCDS distribution costs are based on demand (\$ per kW), which makes their cost estimate less straight forward. Since the monthly aggregate data did not include demand data, a model was devised to estimate the demand attributable to C&I customers. To accomplish that, the Load Factor (“LF”) was calculated from the interval data sets. LF is defined as the average usage for the time period in question (in this case, one month) divided by the peak demand for the same time period.

$$LF = \frac{P_{average}}{P_{peak}}$$

This implies that the LF will always be less than one. A higher LF indicates a “flat” demand profile. Typically, C&I loads have a higher LF than residential loads.

LFs were then calculated by municipality, for each month of the study. This calculation was performed on the interval data set. The LF calculated from the interval data was then applied back to the aggregate usage to estimate the peak demand needed for T&D cost

calculations. Since the peak demand is important for C&I loads only, the formula used for this calculation was:

$$P_{peak,C\&I} = F_{C\&I} \left(\frac{P_{average}}{LF_{Interval}} \right)$$

Where $F_{C\&I}$ is the fraction of the monthly aggregate usage from C&I customers.

This model assumes that the overall LF of the interval data is representative of the C&I load. Since, as mentioned above, C&I loads typically have a higher LF than residential, the model may assign a higher peak demand to the C&I load, which would raise the associated distribution charges.

To determine the impact of load reduction programs on municipal savings, a simple load management program was simulated. Under this program, demand during the peak summer months (as defined by ComEd) was reduced by 10%. This algorithm was applied to the interval data prior to running the usage through the HEP data. Included in the explanation of the load reduction study in Appendix D, is the qualifying condition that not all implementation costs are included. As such, the report sets forth the savings from the 10% summer load reduction as a “what if” scenario and no general conclusions should be drawn until more is known about implementation costs.

C. Cost Comparisons and Savings Under Municipal Aggregation

Cost comparisons in this report do not include franchise fees, taxes, decommissioning charges, other riders, and transition charges. Including all taxes and adders would reduce the percentage savings because the base cost comparisons would be larger, but the dollar amount of savings would remain the same. Including transition charges would significantly reduce all savings, and, to the extent that savings remain, they will most likely be consistent with the mitigation factors for customer classes. Savings for individual customers would depend on the customers using less kWh per kW of demand in each respective customer class. The latter is the result of the formula for calculating transition charges, and is unique in that respect, i.e., it should not be inferred that lower LF customers are less costly to serve, but the facts are simply that transition charges erode a greater share of the savings for high LF customers. For most customers, savings would be lowered to the respective mitigation factors in those years, see Table 1, which would dramatically reduce savings. For example, the mitigation factor for residential customers in 2003 is 7%.

Table 2 sets forth a comparison of the total costs to consumers under bundled rates versus aggregation or market supply, and bundled rates versus aggregation with a 10% summer load reduction, for all four years of pricing data and for each community participating in the study. The bundled rate figures do not include load reduction because the report assumes that there is little or no incentive for customers to reduce load when they pay average rates under fixed price contracts. In 2007, when the mandatory rate freeze expires, a utility’s market purchases will be reflected in its bundled rates, and, to the extent that the utility’s rates move with the market or a

market index, and to the extent that wholesale prices increase significantly, then it is possible that bundled rate customers would reduce load as well. The potential savings appear significant and are set forth in Tables 3 through 6.

Including different years in the analysis demonstrates to some degree how changes in wholesale prices may change the savings under municipal aggregation programs. For example, Table 3 sets forth the results for 1999, which was a year with abnormally warmer summer weather. The HEP 1999 wholesale summer prices are 3.5 to 4 times greater on average than for the other years included in the study. HEP wholesale prices for the entire year of 1999 are 1.5 to 1.9 times greater on average than for the other years included in the study. Under the higher 1999 power prices, savings turn in to higher costs for every community except Woodstock. These results should encourage a municipality to exercise caution if they consider aggregation, especially when one considers that a potentially flawed market structure and manipulation of market prices are not factored in to this analysis. Flawed market structure and manipulation of prices have shown in California to affect prices year round and to be much more costly than periodically unseasonably warm weather.

This report previously discussed several factors that appear to result in no RES activity for residential customers, and one of those factors, load profile (the distribution of hourly customer demand over a period of time, described in aggregate as a load factor) is demonstrated to a degree in each of Table 2 – Table 6. From a review of the usage data by community, it appears that communities that have the highest share of residential usage on bundled rates, e.g., Park Forest and De Kalb, 73% and 45%, respectively, also achieve the lowest potential savings. By comparison, the percentage of residential customers on bundled rates in Woodstock, Evanston, and Kankakee is 23%, 29%, and 33%, respectively. The higher cost to serve residential customers, due to their less attractive load profile, could be problematic for a municipality that chooses to aggregate. If C&I customers opt out to ensure that they maximize their own potential savings, then the municipality may be left serving a predominantly residential load at a higher-cost load and cannot deliver the originally expected level of savings. Nevertheless, the potential savings for predominantly residential communities like Park Forest and De Kalb may warrant consideration by similarly situated communities.

Since weather events will continue to affect wholesale energy prices, the report compares energy costs and savings for bundled versus aggregated customers if load management programs reduced usage in the summer months to offset the effect of higher prices. Thus, the next step is to take the model described above and factor in possibilities for reshaping the load profile of the community. For this model, a 10% reduction in summer demand (June 15 – September 15) was used, which is consistent with models in the study, “Community Based Energy Program A Study Of Load Aggregation And Peak Demand Reduction”, prepared by the University of Illinois at Chicago/Energy Resources Center, ICF Consulting, the Illinois Department of Natural Resources, and National Economic Research Associates, June, 2001. See Appendix D in this report for a summary of the load reduction study. The 10% load reduction is applied to 2001 interval data, which is the only full year of data obtained for the report.

The 10% summer load reduction scenario includes the cost of interval meters and installation for residential and small commercial customers (up to 400 kW.) The interval meter

cost estimate used cost data provided by ComEd for the self contained ABB A1 Alpha Plus interval meter. The reported meter cost is \$150 per meter plus \$45 to exchange the meter. A ten year period was assume for amortization. Depreciation, capital cost, and taxes are based upon the Commission's Order in ComEd's most recent delivery services rate case, Docket No. 01-0423, Interim Order, April 10, 2002. A monthly charge of \$3.27 per meter was calculated for interval meters. A credit, per the Rate RCDS tariff, is applied to this charge to reflect the reduction in costs from the removal of ComEd's existing meters. Total annual interval meter costs, net of the credit for removing the existing ComEd meter, for each community, are set forth on Table 7, Net Annual Interval Meter Costs.

While these analyses use historical data and market conditions to demonstrate significant value from aggregation and targeted load management, future energy market conditions are unknown and the results will most likely be different. From 2000 through the present, Illinois has experienced low wholesale prices for electricity, which would translate into savings under an aggregation model. If opt-out or all-in municipal aggregation is provided in the future, then municipalities should exercise caution in their decisions to participate. As mentioned previously, conditions in the wholesale market can change quickly and estimates of savings can quickly evaporate and leave a municipality with an unanticipated liability for power supply costs.

Table 8 sets forth an estimate of transition charges and their effect on the estimate of savings that use the 2002 set of prices. Transition charges are set forth in the ComEd tariffs for delivery services by customer class. The report utilized the most recently approved transition charges, which are for Period A, January – May 2003. The report did not apply transition charges to the cost estimates for 1999 – 2001 because residential customers were not eligible for open access prior to May 2002 and no transition charges existed for this class prior to May 2002. Transition charges reduce the savings estimates substantially and, in general, it should be expected that transition charges reduce potential savings down to about the statutory mitigation factor for a particular year and class of customers. Transition charges are calculated at a specific time during the year, and for a set of expected market prices for power at that time, but actual market prices for an alternative supplier will differ over that time period. To the extent that actual market values are lower (higher) than those set forth in the transition charge calculation, than actual savings may exceed (be less than) the mitigation factor.

Table 2 – Total Cost Comparisons and Savings 1999 - 2002

	1999 - 2002 Bundled Costs	1999 - 2002 Market Aggregation Costs	1999 - 2002 Market Aggregation Costs With 10% Decrease in Summer Load	% Savings No Load Reduction	% Savings With 10% Load Reduction
De Kalb	\$67,990,992	\$56,289,105	\$55,310,169	17.21%	18.65%
Elgin	\$203,151,140	\$160,936,180	\$156,638,455	20.78%	22.90%
Evanston	\$169,187,649	\$135,164,481	\$132,241,014	20.11%	21.84%
Kankakee	\$70,299,672	\$55,240,974	\$53,627,528	21.42%	23.72%

Park Forest	\$30,400,743	\$25,037,783	\$24,678,776	17.64%	18.82%
Woodstock	\$66,763,044	\$47,740,109	\$46,499,691	28.49%	30.35%
Aggregate	\$607,793,241	\$480,408,632	\$468,995,632	20.96%	22.84%

Table 3 – Cost Comparisons and Savings 1999

	1999 Bundled Costs	1999 Market Aggregation Costs	1999 Market Aggregation Costs With 10% Decrease in Summer Load	% Savings No Load Reduction	% Savings With 10% Load Reduction
De Kalb	\$16,997,748	\$18,476,241	\$17,742,519	-8.70%	-4.38%
Elgin	\$50,787,785	\$55,007,296	\$52,315,164	-8.31%	-3.01%
Evanston	\$42,296,912	\$46,251,244	\$44,141,808	-9.35%	-4.36%
Kankakee	\$17,574,918	\$19,003,998	\$18,051,378	-8.13%	-2.71%
Park Forest	\$7,600,186	\$8,362,327	\$8,049,521	-10.03%	-5.91%
Woodstock	\$16,690,761	\$15,843,971	\$15,083,685	5.07%	9.63%
Aggregate	\$151,948,310	\$162,945,077	\$155,384,075	-7.24%	-2.26%

Table 4 – Cost Comparisons and Savings 2000

	2000 Bundled Costs	2000 Market Aggregation Costs	2000 Market Aggregation Costs With 10% Decrease in Summer Load	% Savings No Load Reduction	% Savings With 10% Load Reduction
De Kalb	\$16,997,748	\$13,021,173	\$12,954,243	23.39%	23.79%
Elgin	\$50,787,785	\$36,552,777	\$36,074,958	28.03%	28.97%
Evanston	\$42,296,912	\$30,932,800	\$30,695,181	26.87%	27.43%
Kankakee	\$17,574,918	\$12,476,721	\$12,306,241	29.01%	29.98%
Park Forest	\$7,600,186	\$5,724,699	\$5,722,928	24.68%	24.70%
Woodstock	\$16,690,761	\$10,991,783	\$10,830,777	34.14%	35.11%
Aggregate	\$151,948,310	\$109,699,952	\$108,584,329	27.80%	28.54%

Table 5 – Cost Comparisons and Savings 2001

	2001 Bundled Costs	2001 Market Aggregation Costs	2001 Market Aggregation Costs With 10% Decrease in Summer Load	% Savings No Load Reduction	% Savings With 10% Load Reduction
De Kalb	\$16,997,748	\$13,283,571	\$13,140,667	21.85%	22.69%
Elgin	\$50,787,785	\$37,540,529	\$36,789,850	26.08%	27.56%
Evanston	\$42,296,912	\$31,369,531	\$30,940,471	25.83%	26.85%
Kankakee	\$17,574,918	\$12,947,400	\$12,592,208	26.33%	28.35%
Park Forest	\$7,600,186	\$5,845,762	\$5,789,180	23.08%	23.83%
Woodstock	\$16,690,761	\$11,308,354	\$11,122,677	32.25%	33.36%
Aggregate	\$151,948,310	\$112,295,148	\$110,375,054	26.10%	27.36%

Table 6 – Cost Comparisons and Savings 2002

	2002 Bundled Costs	2002 Market Aggregation Costs	2002 Market Aggregation Costs With 10% Decrease in Summer Load	% Savings No Load Reduction	% Savings With 10% Load Reduction
De Kalb	\$16,997,748	\$11,508,120	\$11,472,739	32.30%	32.50%
Elgin	\$50,787,785	\$31,835,578	\$31,458,482	37.32%	38.06%
Evanston	\$42,296,912	\$26,610,906	\$26,463,554	37.09%	37.43%
Kankakee	\$17,574,918	\$10,812,856	\$10,677,701	38.48%	39.24%
Park Forest	\$7,600,186	\$5,104,995	\$5,117,146	32.83%	32.67%
Woodstock	\$16,690,761	\$9,596,002	\$9,462,551	42.51%	43.31%
Aggregate	\$151,948,310	\$95,468,456	\$94,652,174	37.17%	37.71%

Table 7 Net Annual Interval Meter Costs

	Residential & C/I Annual Cost of Interval Meters
De Kalb	\$325,643
Elgin	\$648,911
Evanston	\$725,087
Kankakee	\$214,360
Park Forest	\$181,048
Woodstock	\$158,062
Aggregate	\$2,253,111

Table 8 Transition Charges and Savings Estimates

	2003 Transition Charges Applied to 2001 Usage	2002 Savings Net Transition Charges No load Reduction	2002 Savings Net Transition Charges With 10% Summer Load Reduction	2002 Revised % Savings No Load Reduction	2002 Revised % Savings With 10% Summer Load Reduction
De Kalb	\$6,104,509	(\$614,881)	(\$579,500)	-3.62%	-3.41%
Elgin	\$16,211,894	\$2,740,314	\$3,117,409	5.40%	6.14%
Evanston	\$9,961,915	\$5,724,091	\$5,871,443	13.53%	13.88%
Kankakee	\$6,665,132	\$96,931	\$232,085	0.55%	1.32%
Park Forest	\$1,732,665	\$762,526	\$750,375	10.03%	9.87%
Woodstock	\$4,493,146	\$2,601,613	\$2,735,064	15.59%	16.39%
Aggregate	\$45,169,260	\$11,310,594	\$12,126,876	7.44%	7.98%

VIII. Barriers to Municipal Aggregation

Previous sections have describes potential economic and other potential benefits from aggregation in general and municipal aggregation in particular. However, there are a variety of legal, institutional, information/technology and energy market development issues that stand as barriers to the implementation of municipal aggregation in Illinois. This section will outline these barriers and set forth a preliminary set of options for overcoming these barriers. The options are consistent with findings from the efforts in other states to implement municipal aggregation.

A. Legal

As described in Section II, the Customer Choice Law contains some brief references to the possibility of aggregation of customer demand. However, based upon the experience of other states, additional enabling language in the law is necessary to allow for successful municipal aggregations. Requiring a municipal aggregator to become an ARES appears to be a barrier to municipal aggregation because of certain requirements set forth in Section 16-115 and Section 16-115A of the Customer Choice Law.

Section 16-115A(b) of the Customer Choice Law appears to preclude the opt-out and all-in methods of municipal aggregation because it requires that an ARES obtain verifiable authorization prior to switching a customer. The customer authorization must be in a form or manner approved by the Commission and consistent with Section 2EE of the Consumer Fraud and Deceptive Business Practice Act. This requirement is satisfied by written authorization from the customer to switch suppliers. If a municipal aggregator must become an ARES, then the savings on customer acquisition costs from the opt-out and all-in methods would most likely disappear. This requirement is also applicable to all RESs via the terms and conditions of an electric utility's delivery services tariffs, as provided by section 16-116(a) of the Customer Choice Law.

Section 16-115(d)(5) of the Customer Choice Law may limit supply options for municipal aggregators, if they are required to be ARESs, depending on whether their principal source of electricity complies with this section. This section is commonly referred to as the reciprocity section of the Customer Choice Law. If the municipality, as an ARES, obtains its electricity from a single source that accounts for at least 65% of the municipality's power and energy, then this supplier must meet the reciprocity requirement and provide delivery services that are reasonably comparable to those provided by the electric utility serving the municipality. This requirement could substantially limit the number of eligible suppliers for a municipality.

B. Institutional

Aggregation of electrical demand is new to most municipal governments, and therefore a variety of new institutions, regulations, and procedures need to be developed at both the state and local level.

One of the essentials for capturing the value of aggregation is having a capable aggregator. In examining the institutions, other than electric utilities, municipalities stand out as qualified. Municipalities have experience in contracting for and providing public services, such as water, sanitation, police, fire, and emergency services. They also allow for aggregation that is generally geographically compact and that often corresponds with the electricity distribution system components. This can improve the potential for the use of distributed generation, alternative energy, and demand management technologies.

However, negotiating power contracts and running demand management programs, such as those previously described, are skills that most municipalities do not have at this time. Nevertheless, as has been shown in Ohio and Massachusetts, the newness of municipal aggregation is not an insurmountable barrier to implementation. Municipalities have already been innovative in securing the expertise they need to implement aggregation. As has been shown in Ohio with NOPEC, aggregation laws that allow municipalities to work together to implement aggregation may increase participation among smaller communities.

C. Information, Technology and Market Conditions

With the end of the traditional vertically integrated utility model, the information and technology needs that face new market participants are substantial. While quality data was available from one Illinois utility to conducting this study, similar data was not available elsewhere in the state. (The data that was available did not always fit well to municipal boundaries.) For this study, it was appropriate and possible, within an acceptable degree of accuracy, to build a data model to adjust for the differences in data sets, but for actual negotiation of electric service contracts, such modeling has risks because each municipality will require a greater degree of accuracy in calculating their expected costs from alternative suppliers. Thus, a need exists for increasing the quality and availability of data about consumption and load shapes on a smaller scale than is currently available so that municipalities can have an accurate and marketable way of determining their community's energy usage and costs. This can come about through improvements in utility data collection, such as the implementation of systems that measure the hourly loads on electrical circuits. Such systems are commonly referred to as supervisory control and data acquisition ("SCADA"). With SCADA on all feeders, and through improvements in the collection of customer level data through advanced metering technology to record real time energy usage patterns, municipalities can obtain accurate hourly measures of the load of customers within their boundaries. Accurate hourly load data is essential to realizing the benefits of real time pricing, energy efficiency programs, and for accurately billing customers for their energy usage. Absent hourly load data, it is possible that the utility and the municipality could agree on hourly load profiles for customers for billing purposes. Utilities are currently entitled to recover prudently incurred delivery services costs, so mandated SCADA systems, although beneficial, may increase delivery costs for all customers.

In addition to accurate and complete data on energy use, an open, robust, and transparent market for electricity will also benefit efforts to develop aggregation. For this study, the ComEd Rate HEP historical pricing data was used as it reflects prices based on indexes from energy exchanges coming into the ComEd service territory. Over the longer term, timely and complete

access to those energy markets will be an essential component of the price negotiations undertaken by municipalities.

IX. Recommendations

The Illinois Commerce Commission makes the following recommendations to further explore and implement municipal aggregation.

A. Recommendation One

For Illinois municipalities to take advantage of the most efficient forms of municipal aggregation, opt-out and all-in aggregation, current statutory provisions must be refined. Provisions to explicitly authorize opt-out and all-in aggregation could include a framework for municipalities to authorize aggregation efforts. Additionally, the consumer switching provisions in the Customer Choice Law would need to be updated to allow municipalities to act on behalf of their residents and businesses that choose to participate.

B. Recommendation Two

Further study of the actions necessary to develop the legal, institutional, and technical capacity for Illinois communities to develop municipal aggregations is needed. The General Assembly and the Governor may wish to consider the appointment of a Task Force to fulfill this need. The report of this Task Force should be submitted within eighteen months after its formation in order to expedite any further changes that may need to be made prior to the end of the transition period.

X. Conclusion

Municipal aggregation, through the opt-out and all-in methods, appears to offer potential suppliers a cost effective means of constructing large purchasing groups that may take advantage of the opportunity to achieve savings through bulk purchasing. The opportunity to achieve savings is not a guarantee and depends largely on factors that are beyond the scope of this report, but municipalities should have an opportunity to carefully consider the potential risks versus the potential benefits for their constituents. Given the higher costs associated with acquiring and serving residential customers, municipal aggregation may represent the only alternative to mandated rate reductions that can provide lower power costs to residential customers.

Appendix A: Text of Public Act 92-0585

The Commission shall prepare a report on the value of municipal aggregation of electricity customers. The report shall be filed with the General Assembly and the Governor no later than January 15, 2003 and shall be publicly available. The report shall, at a minimum, include:

- (1) a description and analysis of actual and potential forms of aggregation of electricity customers in Illinois and in the other states, including aggregation through municipal, affinity, and other organizations and through aggregation of consumer purchases of electricity from renewable energy sources;
- (2) estimates of the potential benefits of municipal aggregation to Illinois electricity customers in at least 5 specific municipal examples comparing their costs under bundled rates and unbundled rates, including real-time prices;
- (3) a description of the barriers to municipal and other forms of aggregation in Illinois, including legal, economic, informational, and other barriers; and
- (4) options for legislative action to foster municipal and other forms of aggregation of electricity customers.

In preparing the report, the Commission shall consult with persons involved in aggregation or the study of aggregation of electricity customers in Illinois, including municipalities, utilities, aggregators, and non-profit organizations. The provisions of Section 16-122 notwithstanding, the Commission may request and utilities shall provide such aggregated load data as may be necessary to perform the analyses required by this subsection; provided, however, proprietary or confidential information shall not be disclosed publicly.

Appendix B: Provisions relating to Aggregation in the 1997 Restructuring Law

§16-102. Definitions. For the purposes of this Article the following terms shall be defined as set forth in this Section.

"Alternative retail electric supplier" means every person, cooperative, corporation, municipal corporation, company, association, joint stock company or association, firm, partnership, individual, or other entity, their lessees, trustees, or receivers appointed by any court whatsoever, that offers electric power or energy for sale, lease or in exchange for other value received to one or more retail customers, or that engages in the delivery or furnishing of electric power or energy to such retail customers, and shall include, without limitation, resellers, aggregators and power marketers, but shall not include (i) electric utilities (or any agent of the electric utility to the extent the electric utility provides tariffed services to retail customers through that agent), (ii) any electric cooperative or municipal system as defined in Section 17-100 to the extent that the electric cooperative or municipal system is serving retail customers within any area in which it is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, (iii) a public utility that is owned and operated by any public institution of higher education of this State, or a public utility that is owned by such public institution of higher education and operated by any of its lessees or operating agents, within any area in which it is or would be entitled to provide service under the law in effect immediately prior to the effective date of this amendatory Act of 1997, (iv) any retail customer to the extent that customer obtains its electric power and energy from its own cogeneration or self-generation facilities, (v) any entity that sells or arranges for the installation of cogeneration or self-generation facilities to be owned by a retail customer described in subparagraph (iv), but only to the extent the entity is engaged in selling or arranging for such installation, or (vi) an industrial or manufacturing customer that owns its own distribution facilities, to the extent that the customer provides service from that distribution system to a third-party contractor located on the customer's premises that is integrally and predominantly engaged in the customer's industrial or manufacturing process; provided, that if the industrial or manufacturing customer has elected delivery services, the customer shall pay transition charges applicable to the electric power and energy consumed by the third-party contractor unless such charges are otherwise paid by the third party contractor, which shall be calculated based on the usage of, and the base rates or the contract rates applicable to, the third-party contractor in accordance with Section 16-102.

"Mandatory transition period" means the period from the effective date of this amendatory Act of 1997 through January 1, 2007.

"Transition charge" means a charge expressed in cents per kilowatt-hour that is calculated for a customer or class of customers as follows for each year in which an electric utility is entitled to recover transition charges as provided in Section 16-108:

- (1) the amount of revenue that an electric utility would receive from the retail customer or customers if it were serving such customers' electric power and energy requirements as a tariffed service based on (A) all of the customers' actual usage during

the 3 years ending 90 days prior to the date on which such customers were first eligible for delivery services pursuant to Section 16-104, and (B) on (i) the base rates in effect on October 1, 1996 (adjusted for the reductions required by subsection (b) of Section 16-111, for any reduction resulting from a rate decrease under Section 16-101(b), for any restatement of base rates made in conjunction with an elimination of the fuel adjustment clause pursuant to subsection (b), (d), or (f) of Section 9-220 and for any removal of decommissioning costs from base rates pursuant to Section 16-114) and any separate automatic rate adjustment riders (other than a decommissioning rate as defined in Section 16-114) under which the customers were receiving or, had they been customers, would have received electric power and energy from the electric utility during the year immediately preceding the date on which such customers were first eligible for delivery service pursuant to Section 16-104, or (ii) to the extent applicable, any contract rates, including contracts or rates for consolidated or aggregated billing, under which such customers were receiving electric power and energy from the electric utility during such year;

(2) less the amount of revenue, other than revenue from transition charges and decommissioning rates, that the electric utility would receive from such retail customers for delivery services provided by the electric utility, assuming such customers were taking delivery services for all of their usage, based on the delivery services tariffs in effect during the year for which the transition charge is being calculated and on the usage identified in paragraph (1);

(3) less the market value for the electric power and energy that the electric utility would have used to supply all of such customers' electric power and energy requirements, as a tariffed service, based on the usage identified in paragraph (1), with such market value determined in accordance with Section 16-112 of this Act;

(4) less the following amount which represents the amount to be attributed to new revenue sources and cost reductions by the electric utility through the end of the period for which transition costs are recovered pursuant to Section 16-108, referred to in this Article XVI as a "mitigation factor":

(A) for nonresidential retail customers, an amount equal to the greater of (i) 0.5 cents per kilowatt-hour during the period October 1, 1999 through December 31, 2004, 0.6 cents per kilowatt-hour in calendar year 2005, and 0.9 cents per kilowatt-hour in calendar year 2006, multiplied in each year by the usage identified in paragraph (1), or (ii) an amount equal to the following percentages of the amount produced by applying the applicable base rates (adjusted as described in subparagraph (1)(B)) or contract rate to the usage identified in paragraph (1): 8% for the period October 1, 1999 through December 31, 2002, 10% in calendar years 2003 and 2004, 11% in calendar year 2005 and 12% in calendar year 2006; and

(B) for residential retail customers, an amount equal to the following percentages of the amount produced by applying the base rates in effect on

October 1, 1996 (adjusted as described in subparagraph (1)(B)) to the usage identified in paragraph (1): (i) 6% from May 1, 2002 through December 31, 2002, (ii) 7% in calendar years 2003 and 2004, (iii) 8% in calendar year 2005, and (iv) 10% in calendar year 2006;

(5) divided by the usage of such customers identified in paragraph (1), provided that the transition charge shall never be less than zero.

(§16-104-b) Delivery services transition plan.

(b) The electric utility shall allow the aggregation of loads that are eligible for delivery services so long as such aggregation meets the criteria for delivery of electric power and energy applicable to the electric utility established by the regional reliability council to which the electric utility belongs, by an independent system operating organization to which the electric utility belongs, or by another organization responsible for overseeing the integrity and reliability of the transmission system, as such criteria are in effect from time to time. The Commission may adopt rules and regulations governing the criteria for aggregation of the loads utilizing delivery services, but its failure to do so shall not preclude any eligible customer from electing delivery services. The electric utility shall allow such aggregation for any voluntary grouping of customers, including without limitation those having a common agent with contractual authority to purchase electric power and energy and delivery services on behalf of all customers in the grouping.

(c) An electric utility shall allow a retail customer that generates power for its own use to include the electrical demand obtained from the customer's cogeneration or self-generation facilities that is coincident with the retail customer's maximum monthly electrical demand on the electric utility's system in any determination of the customer's maximum monthly electrical demand for purposes of determining when such retail customer shall be offered delivery services pursuant to clause (i) of subparagraph (1) of subsection (a) of this Section.

(d) The Commission shall establish charges, terms and conditions for delivery services in accordance with Section 16-108.

(e) Subject to the terms and conditions which the electric utility is entitled to impose in accordance with Section 16-108, a retail customer that is eligible to elect delivery services pursuant to subsection (a) may place all or a portion of its electric power and energy requirements on delivery services.

Section 16-108 (f), (g), and (h)

(f) An electric utility shall be entitled but not required to implement transition charges in conjunction with the offering of delivery services pursuant to Section 16-104. If an electric utility implements transition charges, it shall implement such charges for all delivery services customers and for all customers described in subsection (h), but shall not implement transition charges for power and energy that a retail customer takes from cogeneration or self-generation facilities located on that retail customer's premises, if such facilities meet the following criteria:

(i) the cogeneration or self-generation facilities serve a single retail customer and are located on that retail customer's premises (for purposes of this subparagraph and

subparagraph (ii), an industrial or manufacturing retail customer and a third party contractor that is served by such industrial or manufacturing customer through such retail customer's own electrical distribution facilities under the circumstances described in subsection (vi) of the definition of "alternative retail electric supplier" set forth in Section 16-102, shall be considered a single retail customer);

(ii) the cogeneration or self-generation facilities either (A) are sized pursuant to generally accepted engineering standards for the retail customer's electrical load at that premises (taking into account standby or other reliability considerations related to that retail customer's operations at that site) or (B) if the facility is a cogeneration facility located on the retail customer's premises, the retail customer is the thermal host for that facility and the facility has been designed to meet that retail customer's thermal energy requirements resulting in electrical output beyond that retail customer's electrical demand at that premises, comply with the operating and efficiency standards applicable to "qualifying facilities" specified in title 18 Code of Federal Regulations Section 292.205 as in effect on the effective date of this amendatory Act of 1999;

(iii) the retail customer on whose premises the facilities are located either has an exclusive right to receive, and corresponding obligation to pay for, all of the electrical capacity of the facility, or in the case of a cogeneration facility that has been designed to meet the retail customer's thermal energy requirements at that premises, an identified amount of the electrical capacity of the facility, over a minimum 5-year period; and

(iv) if the cogeneration facility is sized for the retail customer's thermal load at that premises but exceeds the electrical load, any sales of excess power or energy are made only at wholesale, are subject to the jurisdiction of the Federal Energy Regulatory Commission, and are not for the purpose of circumventing the provisions of this subsection (f).

If a generation facility located at a retail customer's premises does not meet the above criteria, an electric utility implementing transition charges shall implement a transition charge until December 31, 2006 for any power and energy taken by such retail customer from such facility as if such power and energy had been delivered by the electric utility. Provided, however, that an industrial retail customer that is taking power from a generation facility that does not meet the above criteria but that is located on such customer's premises will not be subject to a transition charge for the power and energy taken by such retail customer from such generation facility if the facility does not serve any other retail customer and either was installed on behalf of the customer and for its own use prior to January 1, 1997, or is both predominantly fueled by byproducts of such customer's manufacturing process at such premises and sells or offers an average of 300 megawatts or more of electricity produced from such generation facility into the wholesale market. Such charges shall be calculated as provided in Section 16-102, and shall be collected on each kilowatt-hour delivered under a delivery services tariff to a retail customer from the date the customer first takes delivery services until December 31, 2006 except as provided in subsection (h) of this Section. Provided, however, that an electric utility, other than an electric utility providing service to at least 1,000,000 customers in this State on January 1, 1999, shall be entitled to petition for entry of an order by the Commission authorizing the

electric utility to implement transition charges for an additional period ending no later than December 31, 2008. The electric utility shall file its petition with supporting evidence no earlier than 16 months, and no later than 12 months, prior to December 31, 2006. The Commission shall hold a hearing on the electric utility's petition and shall enter its order no later than 8 months after the petition is filed. The Commission shall determine whether and to what extent the electric utility shall be authorized to implement transition charges for an additional period. The Commission may authorize the electric utility to implement transition charges for some or all of the additional period, and shall determine the mitigation factors to be used in implementing such transition charges; provided, that the Commission shall not authorize mitigation factors less than 110% of those in effect during the 12 months ended December 31, 2006. In making its determination, the Commission shall consider the following factors: the necessity to implement transition charges for an additional period in order to maintain the financial integrity of the electric utility; the prudence of the electric utility's actions in reducing its costs since the effective date of this amendatory Act of 1997; the ability of the electric utility to provide safe, adequate and reliable service to retail customers in its service area; and the impact on competition of allowing the electric utility to implement transition charges for the additional period.

(g) The electric utility shall file tariffs that establish the transition charges to be paid by each class of customers to the electric utility in conjunction with the provision of delivery services. The electric utility's tariffs shall define the classes of its customers for purposes of calculating transition charges. The electric utility's tariffs shall provide for the calculation of transition charges on a customer-specific basis for any retail customer whose average monthly maximum electrical demand on the electric utility's system during the 6 months with the customer's highest monthly maximum electrical demands equals or exceeds 3.0 megawatts for electric utilities having more than 1,000,000 customers, and for other electric utilities for any customer that has an average monthly maximum electrical demand on the electric utility's system of one megawatt or more, and (A) for which there exists data on the customer's usage during the 3 years preceding the date that the customer became eligible to take delivery services, or (B) for which there does not exist data on the customer's usage during the 3 years preceding the date that the customer became eligible to take delivery services, if in the electric utility's reasonable judgment there exists comparable usage information or a sufficient basis to develop such information, and further provided that the electric utility can require customers for which an individual calculation is made to sign contracts that set forth the transition charges to be paid by the customer to the electric utility pursuant to the tariff.

(h) An electric utility shall also be entitled to file tariffs that allow it to collect transition charges from retail customers in the electric utility's service area that do not take delivery services but that take electric power or energy from an alternative retail electric supplier or from an electric utility other than the electric utility in whose service area the customer is located. Such charges shall be calculated, in accordance with the definition of transition charges in Section 16-102, for the period of time that the customer would be obligated to pay transition charges if it were taking delivery services, except that no deduction for delivery services revenues shall be made in such calculation, and usage data from the customer's class shall be used where historical usage data is not available for the individual customer. The customer shall be obligated to pay such charges on a lump sum basis on or before the date on which the

customer commences to take service from the alternative retail electric supplier or other electric utility, provided, that the electric utility in whose service area the customer is located shall offer the customer the option of signing a contract pursuant to which the customer pays such charges ratably over the period in which the charges would otherwise have applied.

Section 16-111(a)

Sec. 16-111. Rates and restructuring transactions during mandatory transition period.

(a) During the mandatory transition period, notwithstanding any provision of Article IX of this Act, and except as provided in subsections (b), (d), (e), and (f) of this Section, the Commission shall not (i) initiate, authorize or order any change by way of increase (other than in connection with a request for rate increase which was filed after September 1, 1997 but prior to October 15, 1997, by an electric utility serving less than 12,500 customers in this state), (ii) initiate or, unless requested by the electric utility, authorize or order any change by way of decrease, restructuring or unbundling (except as provided in Section 16-109A), in the rates of any electric utility that were in effect on October 1, 1996, or (iii) in any order approving any application for a merger pursuant to Section 7-204 that was pending as of May 16, 1997, impose any condition requiring any filing for an increase, decrease, or change in, or other review of, an electric utility's rates or enforce any such condition of any such order; provided, however, that this subsection shall not prohibit the Commission from:

(1) approving the application of an electric utility to implement an alternative to rate of return regulation or a regulatory mechanism that rewards or penalizes the electric utility through adjustment of rates based on utility performance, pursuant to Section 9-244;

(2) authorizing an electric utility to eliminate its fuel adjustment clause and adjust its base rate tariffs in accordance with subsection (b), (d), or (f) of Section 9-220 of this Act, to fix its fuel adjustment factor in accordance with subsection (c) of Section 9-220 of this Act, or to eliminate its fuel adjustment clause in accordance with subsection (e) of Section 9-220 of this Act;

(3) ordering into effect tariffs for delivery services and transition charges in accordance with Sections 16-104 and 16-108, for real-time pricing in accordance with Section 16-107, or the options required by Section 16-110 and subsection (n) of 16-112, allowing a billing experiment in accordance with Section 16-106, or modifying delivery services tariffs in accordance with Section 16-109; or

(4) ordering or allowing into effect any tariff to recover charges pursuant to Sections 9-201.5, 9-220.1, 9-221, 9-222 (except as provided in Section 9-222.1), 16-108, and 16-114 of this Act, Section 5-5 of the Electricity Infrastructure Maintenance Fee Law, Section 6-5 of the Renewable Energy, Energy Efficiency, and Coal Resources Development Law of 1997, and Section 13 of the Energy Assistance Act of 1989.

After December 31, 2004, the provisions of this subsection (a) shall not apply to an electric utility whose average residential retail rate was less than or equal to 90% of the average residential retail rate for the “Midwest Utilities”, as that term is defined in subsection (b) of this Section, based on data reported on Form 1 to the Federal Energy Regulatory Commission for calendar year 1995, and which served between 150,000 and 250,000 retail customers in this State on January 1, 1995 unless the electric utility or its holding company has been acquired by or merged with an affiliate of another electric utility subsequent to January 1, 2002. This exemption shall be limited to this subsection (a) and shall not extend to any other provisions of this Act.

(b) Notwithstanding the provisions of subsection (a), each Illinois electric utility serving more than 12,500 customers in Illinois shall file tariffs (i) reducing, effective August 1, 1998, each component of its base rates to residential retail customers by 15% from the base rates in effect immediately prior to January 1, 1998 and (ii) if the public utility provides electric service to (A) more than 500,000 customers but less than 1,000,000 customers in this State on January 1, 1999, reducing, effective May 1, 2002, each component of its base rates to residential retail customers by an additional 5% from the base rates in effect immediately prior to January 1, 1998, or (B) at least 1,000,000 customers in this State on January 1, 1999, reducing, effective October 1, 2001, each component of its base rates to residential retail customers by an additional 5% from the base rates in effect immediately prior to January 1, 1998. Provided, however, that (A) if an electric utility's average residential retail rate is less than or equal to the average residential retail rate for a group of Midwest Utilities (consisting of all investor-owned electric utilities with annual system peaks in excess of 1000 megawatts in the States of Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, Ohio, and Wisconsin), based on data reported on Form 1 to the Federal Energy Regulatory Commission for calendar year 1995, then it shall only be required to file tariffs (i) reducing, effective August 1, 1998, each component of its base rates to residential retail customers by 5% from the base rates in effect immediately prior to January 1, 1998, (ii) reducing, effective October 1, 2000, each component of its base rates to residential retail customers by the lesser of 5% of the base rates in effect immediately prior to January 1, 1998 or the percentage by which the electric utility's average residential retail rate exceeds the average residential retail rate of the Midwest Utilities, based on data reported on Form 1 to the Federal Energy Regulatory Commission for calendar year 1999, and (iii) reducing, effective October 1, 2002, each component of its base rates to residential retail customers by an additional amount equal to the lesser of 5% of the base rates in effect immediately prior to January 1, 1998 or the percentage by which the electric utility's average residential retail rate exceeds the average residential retail rate of the Midwest Utilities, based on data reported on Form 1 to the Federal Energy Regulatory Commission for calendar year 2001; and (B) if the average residential retail rate of an electric utility serving between 150,000 and 250,000 retail customers in this State on January 1, 1995 is less than or equal to 90% of the average residential retail rate for the Midwest Utilities, based on data reported on Form 1 to the Federal Energy Regulatory Commission for calendar year 1995, then it shall only be required to file tariffs (i) reducing, effective August 1, 1998, each component of its base rates to residential retail customers by 2% from the base rates in effect immediately prior to January 1, 1998; and (ii) reducing, effective October 1, 2000, each component of its base rates to residential retail customers by 2% from the base rate in effect immediately prior to January 1, 1998; and (iii) reducing, effective October 1, 2002, each component of its base rates to residential retail customers by 1% from the base rates in effect

immediately prior to January 1, 1998. Provided, further, that any electric utility for which a decrease in base rates has been or is placed into effect between October 1, 1996 and the dates specified in the preceding sentences of this subsection, other than pursuant to the requirements of this subsection, shall be entitled to reduce the amount of any reduction or reductions in its base rates required by this subsection by the amount of such other decrease. The tariffs required under this subsection shall be filed 45 days in advance of the effective date. Notwithstanding anything to the contrary in Section 9-220 of this Act, no restatement of base rates in conjunction with the elimination of a fuel adjustment clause under that Section shall result in a lesser decrease in base rates than customers would otherwise receive under this subsection had the electric utility's fuel adjustment clause not been eliminated.

Section 16-115(d)(5)

(5) That if the applicant, its corporate affiliates or the applicant's principal source of electricity (to the extent such source is known at the time of the application) owns or controls facilities, for public use, for the transmission or distribution of electricity to end-users within a defined geographic area to which electric power and energy can be physically and economically delivered by the electric utility or utilities in whose service area or areas the proposed service will be offered, the applicant, its corporate affiliates or principal source of electricity, as the case may be, provides delivery services to the electric utility or utilities in whose service area or areas the proposed service will be offered that are reasonably comparable to those offered by the electric utility, and provided further, that the applicant agrees to certify annually to the Commission that it is continuing to provide such delivery services and that it has not knowingly assisted any person or entity to avoid the requirements of this Section. For purposes of this subparagraph, "principal source of electricity" shall mean a single source that supplies at least 65% of the applicant's electric power and energy, and the purchase of transmission and distribution services pursuant to a filed tariff under the jurisdiction of the Federal Energy Regulatory Commission or a state public utility commission shall not constitute control of access to the provider's transmission and distribution facilities;

Section 16-115A(b)

(b) An alternative retail electric supplier shall obtain verifiable authorization from a customer, in a form or manner approved by the Commission consistent with Section 2EE of the Consumer Fraud and Deceptive Business Practices Act, before the customer is switched from another supplier.

Sec. 16-116.

Commission oversight of electric utilities serving retail customers outside their service areas or providing competitive, non-tariffed services.

(a) An electric utility that has a tariff on file for delivery services may, without regard to any otherwise applicable tariffs on file, provide electric power and energy to one or more retail customers located outside its service area, but only to the extent (i) such retail customer (A) is eligible for delivery services under any delivery services tariff filed with the Commission by the electric utility in whose service area the retail customer is located and (B) has either

elected to take such delivery services or has paid or contracted to pay the charges specified in Sections 16-108 and 16-114, or (ii) if such retail customer is served by a municipal system or electric cooperative, the customer is eligible for delivery services under the terms and conditions for such service established by the municipal system or electric cooperative serving that customer.

(Source: P.A. 90-561, effective December 16, 1997)

(815 ILCS 505/2EE)

Sec. 2EE. Electric service provider selection. An electric service provider shall not submit or execute a change in a subscriber's selection of a provider of electric service except as follows:

The new electric service provider has obtained the customer's written authorization in a form that meets the following requirements:

(1) An electric service provider shall obtain any necessary written authorization from a subscriber for a change in electric service by using a letter of agency as specified in this Section. Any letter of agency that does not conform with this Section is invalid.

(2) The letter of agency shall be a separate document (an easily separable document containing only the authorization language described in subparagraph (5) of this Section) whose sole purpose is to authorize an electric service provider change. The letter of agency must be signed and dated by the subscriber requesting the electric service provider change.

(3) The letter of agency shall not be combined with inducements of any kind on the same document.

(4) Notwithstanding subparagraphs (1) and (2) of this Section, the letter of agency may be combined with checks that contain only the required letter of agency language prescribed in paragraph (5) of this Section and the necessary information to make the check a negotiable instrument. The letter of agency check shall not contain any promotional language or material. The letter of agency check shall contain in easily readable, bold-face type on the face of the check, a notice that the consumer is authorizing an electric service provider change by signing the check. The letter of agency language also shall be placed near the signature line on the back of the check.

(5) At a minimum, the letter of agency must be printed with a print of sufficient size to be clearly legible, and must contain clear and unambiguous language that confirms:

- (i) The subscriber's billing name and address;
- (ii) The decision to change the electric service provider from the current provider to the prospective provider;
- (iii) The terms, conditions, and nature of the service to

be provided to the subscriber must be clearly and conspicuously disclosed, in writing, and an electric service provider must directly establish the rates for the service contracted for by the subscriber; and

(iv) That the subscriber understand that any electric service provider selection the subscriber chooses may involve a charge to the subscriber for changing the subscriber's electric service provider.

(6) Letters of agency shall not suggest or require that a subscriber take some action in order to retain the subscriber's current electric service provider.

(7) If any portion of a letter of agency is translated into another language, then all portions of the letter of agency must be translated into that language.

For purposes of this Section, "electric service provider" shall have the meaning given that phrase in Section 6.5 of the Attorney General Act.

(Source: P.A. 90-561, eff. 12-16-97.)

Appendix C: Summary of Aggregation Projects And Statutes From Other States

	Ohio	Massachusetts	Rhode Island	California
Opt-In vs. Opt-Out	Opt-Out	Opt-Out	Opt-Out	Opt-In
Number of Participants as of Fall 2002	More than 390,000 98 Towns	45,000	None. Law passed and went into effect June 2002.	None
Average Discounts	1-15%	11-22%	N/A	N/A
Opt-out rate	7% in Parma	1%	N/A	N/A
Green Power?	98% Natural Gas, 2% Green	Green Power Option Available	N/A	N/A
Vote required to begin municipal aggregation	Referendum	Majority vote of town meeting or town council	Adoption of ordinance by municipality and referendum	Majority vote of town council
Notification	Aggregator must notify all citizens of intent to switch providers if opt-out is not chosen	Aggregator must notify all citizens of intent to switch providers if opt-out is not chosen	Aggregator must notify all citizens of intent to switch providers if opt-out is not chosen	Aggregator must notify all citizens of intent to switch providers if opt-out is not chosen
Law requires aggregate's price to be lower than customer would pay outside aggregate?	Yes	Yes	In first year, unless it is shown to be lower in subsequent years or the higher cost is due to the purchase of renewable energy	Yes

	Ohio	Massachusetts	Rhode Island	California
Registration Requirements	Aggregator and Marketer must register with the Public Utilities Commission of Ohio and Aggregator must provide business plan with all fees and opt-out policy and have two public meetings about plan	Aggregator must have plan approved by MA Dept. of Telecommunications and Industry	Aggregator must have two public meetings about aggregation plan and submit plan to public utilities commission	Aggregators must have plan approved by California Public Utilities Commission
Time allowed for Opt-Out	21 days and every two years	180 Days	30 days and every two years	60 days
Other aspects of Deregulation Law that have encouraged aggregation	Utilities can only recover stranded costs if they lose 20% of customers to competition Some aggregators able to take advantage of low-priced, regulated “Market Support Generation” electricity.	Aggregators can receive public benefits fund money to run energy efficiency programs		Aggregators are not eligible for public benefits funds
Major Barriers		Initially, state standard offer price was lower than wholesale price. Third party objections can slow contracting and affect price agreements		Exit from utility contracts may be expensive Utilities have been slow to adapt to deregulation 15, 2002
Key Organizations	City of Parama Northeast Ohio Public Energy Council	Cape Light Compact		
Law	SB 3 7/6/1999	HB 5117 11/25/1997	02-H7786Baa 06/13/2002 http://www.rilin.state.ri.us/BillText/BillText02/HouseText02/H7786Baa.pdf	AB 1807 1/1/2002 http://leginfo.ca.gov/pub/01_01_bill_001801_01.html

Appendix D: Summary of Community Based Energy Program Study

In June, 2001 The Illinois Department of Commerce and Community Affairs released a study entitled, *Summary of Community Based Energy Programs: A Study Of Load Aggregation And Peak Demand*. The study was prepared by the University of Illinois at Chicago/Energy Resources Center, ICF Consulting, the Illinois Department of Natural Resources, and National Economic Research Associates.

The purpose of the study was to “investigate/evaluate community oriented energy programs that can enhance electric service reliability and reduce energy service costs, while encouraging the development of a competitive electric market.”²⁸ While the study covers many topic areas, it provides a good case study into the methods that could be used by a community to reduce demand and lower costs for aggregation.

The following table, taken from the study, outlines the most common tools available for demand reduction.

<u>Technology</u>	<u>Overview</u>	<u>Technology Status</u>	<u>Required infrastructure / implementation issues</u>
Energy Efficiency Technologies for Residential Homes			
Air Conditioning	Current minimum standard is 10 SEER. Efficiencies of 14 SEER and higher are available. 14 SEER uses about 40% less energy than a 10 SEER.	Readily available	For proper sizing, install as final step of building improvements
Infiltration Reduction	Weather stripping, Caulking, Sealing penetrations reduce infiltration	Readily available	Only useful in homes with poor envelope
Lighting	High efficiency CFL lighting provides more light with less energy consumption	Readily available	None
Programmable Thermostats	Setback or setup of indoor temperature reduces operation of equipment	Readily available	Special thermostat if Heat pumps are installed
Duct Tightening	Sealed ducts lose less conditioned air to unconditioned spaces	Readily available	accessible ductwork
“Sleep” Mode for PCs	Powers down the computer after a period of inactivity	Readily available	Occupant must activate the feature
Exterior Motion Sensors	Exterior lights are activated by motion and hence are on only when needed	Readily Available	None
Energy Efficiency Technologies for Small Commercial Buildings			
<i>High Efficient Lighting</i>			
Lower Watts/SF	T8 or T5 Fluorescent lighting provides more light per unit input	Readily available	None
Occupancy Sensors	Reduce operation time of lighting when unnecessary	Readily available	Must be appropriate for space type
Reduced Security Ltg	Reduced consumption	Readily available	May be necessary for high

²⁸ UIC, p. 9.

	from unnecessary lighting		risk areas
<i>Building Tune-up</i>			
Clean Filter and Coils	Allows more efficient heat exchange	Readily available	None
Optimize OA Dampers	Reduces the temperature and humidity loads on the cooling system	Readily available	None
<i>Load Reduction</i>			
Roof Insulation to Std 90	Reduces conduction through the roof	Readily available	None
Add Vestibule	Reduces infiltration of hot and humid outdoor air	Readily available	Only in buildings that have the space
Energy Star Computers	Reduce operation of monitors and disk drives	Readily available	None
<i>HVAC Replacement</i>			
Replace Old Motors	Motors operate at same output with less input energy	Readily available	None
Replace Old HVAC	HVAC systems operate at same output with less input energy	Readily available	None
Enthalpy Economizer	Allows for "free cooling" when outdoor air is favorable	Readily available	Only on larger systems with the capability
Load Management / Shifting Technologies			
Load Control Devices/Smart Metering/Energy Management	Enables customer to switch off or adjust equipment for more efficient operation in some automated fashion, based on user input or sensory feedback	Readily available	Utility signal broadcast equipment may be required with certain strategies
Distributed Generation: Microturbines (gas fired)	Use fuel combustion to turn a turbine. Range in size from 25 kW to 200 kW. Have few moving parts and are hence very reliable.	Readily available	Utility gas (e.g., natural gas, propane, or liquid fuels) must be available
Distributed Generation: Wind	Converts wind energy into mechanical movement of turbine blades, then into electricity. Strong, growing market.	Readily available (250 W - 1.5MW)	Sufficient wind resources; open flat terrain (50 acres per MW, but only 5% is not useable for other purposes); visual impacts
Distributed Generation: Fuel Cells	Uses chemical potential to provide power, utilizing hydrogen as the "fuel" source. Clean and quiet with a high electrical efficiency. Still developing in the market.	Readily available on small scale	Hydrogen (comes in natural gas, propane, hydrocarbons, etc.) must be available
Distributed Generation: Photovoltaic (PV)	Converts radiant sunlight energy into electricity using semi-conductor materials. Very clean and	Readily available	Requires sunlight to be effective; needs backup power source and storage component

	quiet. Somewhat costly, but strong market. Able to meet any energy demand.		
Buildings Combined Heat and power (BCHP)	Refers to on-site power generation technologies that produce electrical, mechanical, and useful thermal energy. Excess heat from power production can be used for space heating and DHW as well as for space cooling with absorption chillers and desiccant systems	Readily available	Requires fuel input (natural gas, biogas, oil, etc.); requires customized packaging of available technologies.
Thermal Storage	The process of cooling or freezing a solution (typically water) during off-peak periods so that it can be used during peak hours to cool buildings. Reduces peak loads, not overall energy use.	Readily available	Requires space (up to 20 ft3 per ton-hr of cooling) and cooling material (water)

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The study takes these technologies and creates models using different combinations of these technologies and participation rates to study their potential impact on changing load shapes and the financial incentives necessary for adoption of the these technologies. By mixing these technologies a significant reduction in demand such as the 20% reduction of peak demand is possible. On the financial side, the report concludes that,

“Providing a \$30/kW/year incentive provides significant positive impact on the cost effectiveness of the combination packages. In many cases this level of incentive reduced the simple payback period by as much as 50%. With the estimated cost of constructing new natural gas peaker plants at \$600/kW, and the high cost of transmission and distribution line additions or upgrades, the \$30/kW/year for a three to five year period seems reasonable.”³⁰

Targeted community-based demand management programs are possible using existing as well as emerging technologies. They are cost effective and will produce significant changes in the community’s energy use patterns, with all of the resulting positive impacts.

²⁹ UIC, p. 43.

³⁰ UIC. P. 57.

Appendix E: Community Information

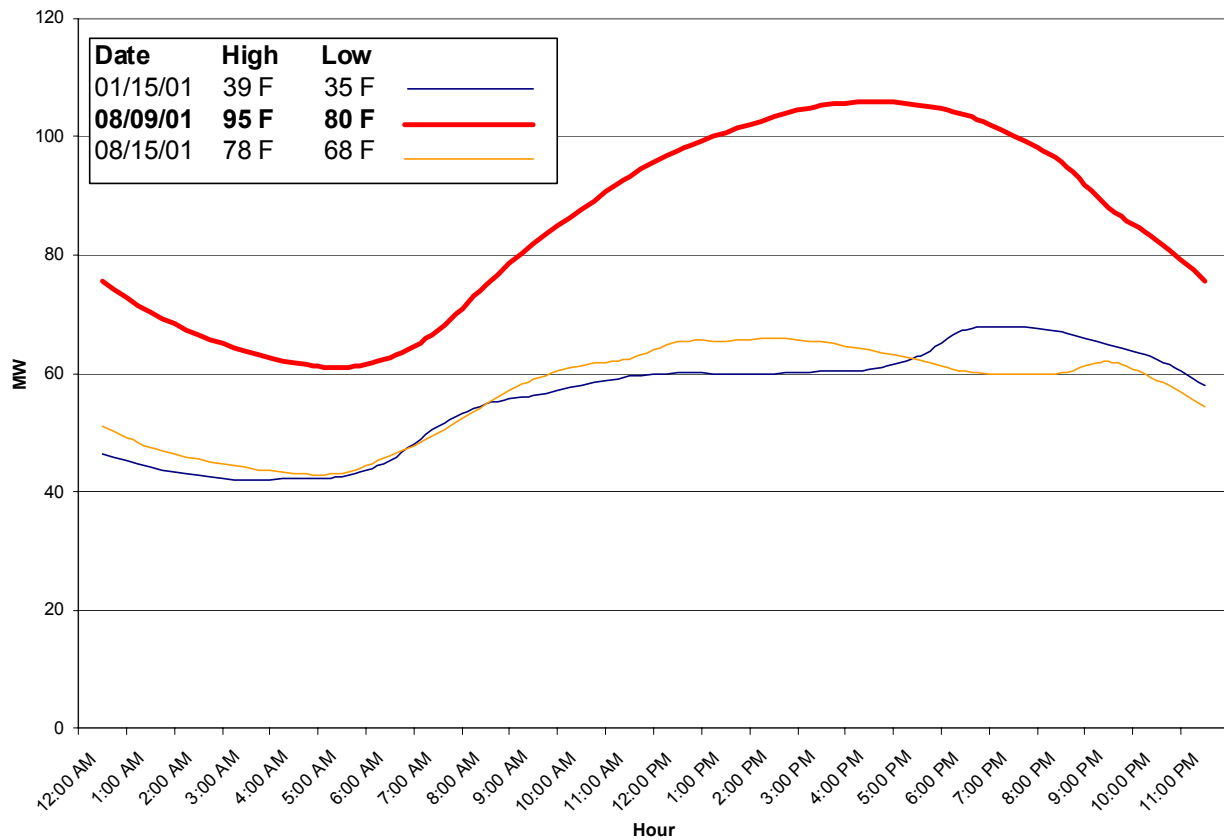
A brief description of each community selected for this report is included in Appendix E. Along with this description, are graphs that set forth the community's load shape on three days, e.g., a typical winter day, a typical summer day and a hot summer day. The data for the load shape graphs comes from the substation that covers a portion of the community. A given transmission substation does not provide an identical match to the municipality's geographic boundaries, so in some instances additional communities are covered, while in other instances the community in question is not covered completely. The load shape graphs show the general profile of the community's energy usage and the impact of weather and time of day on that usage. The cost comparisons in Section VII were developed, in part, from this data.

A. De Kalb

The City of De Kalb is a rapidly growing university community with a rich agricultural history. The city, founded in 1856, has a population of 40,000 and is located an hour's drive west of Chicago. Because it is a university town, a large number of the residents are students.

In addition to being the home of Northern Illinois University, the second largest university in Illinois, De Kalb has a strong manufacturing and agricultural heritage. Commercial mass production of barbed wire fencing began in De Kalb, and the first farm bureau in the nation was founded there. Today, the university is the largest employer, but many other De Kalb businesses are still related to agriculture. The county hospital also employs many people. Housing in De Kalb includes both single-family homes and multi-family units.

Figure 1 De Kalb Community Load Shape



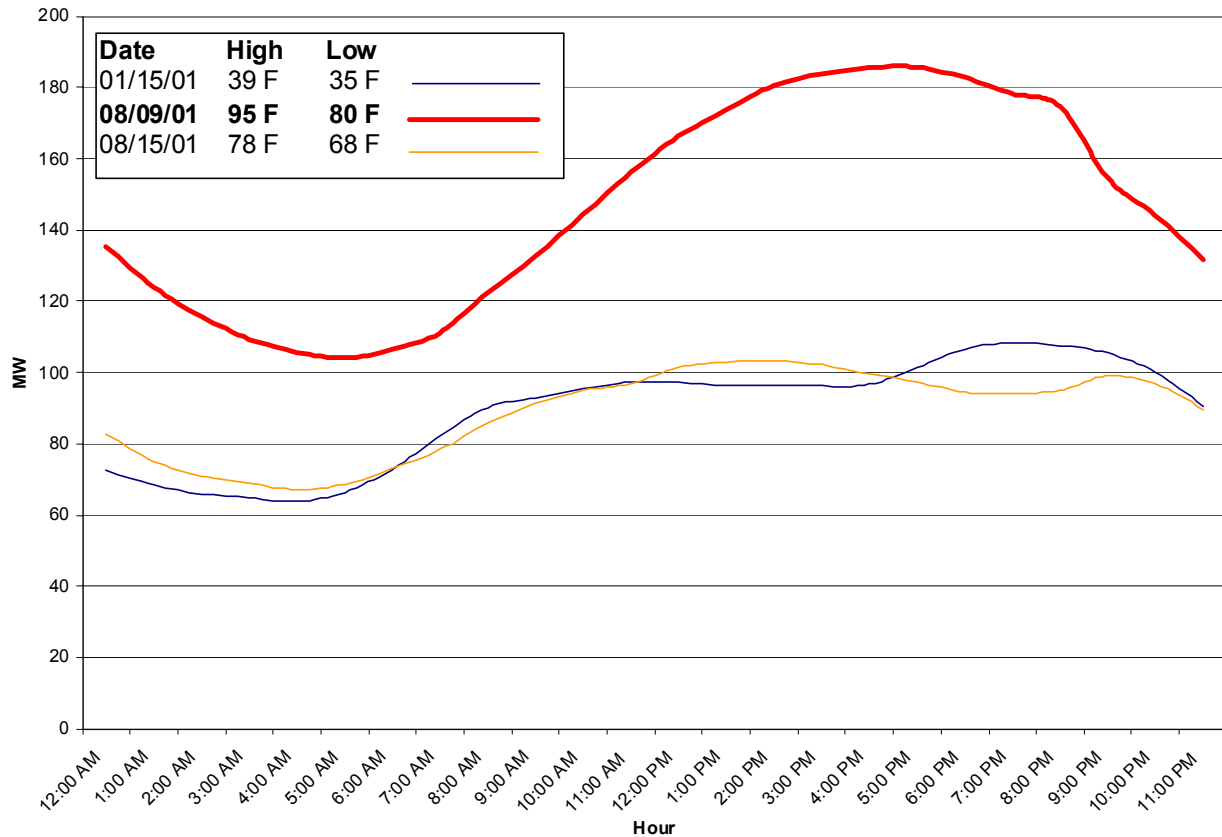
B. Elgin

Situated on the Fox River, the City of Elgin is approximately 38 miles northwest of downtown Chicago and covers an area of about 25 square miles. The city, which straddles Cook and Kane Counties, was incorporated in 1854 and has a population of about 95,000.

Elgin has traditionally been a center for both commerce and industry, and is not dominated by any single industrial sector. In addition to older, established businesses, fifteen companies with foreign headquarters are located there. Elgin is also home to the Grand Victoria Riverboat Casino.

Housing costs in Elgin are comparable to those of neighboring areas, and choices range from late-19th century Victorian houses to newly constructed condominiums.

Figure 2 Elgin Community Load Shape



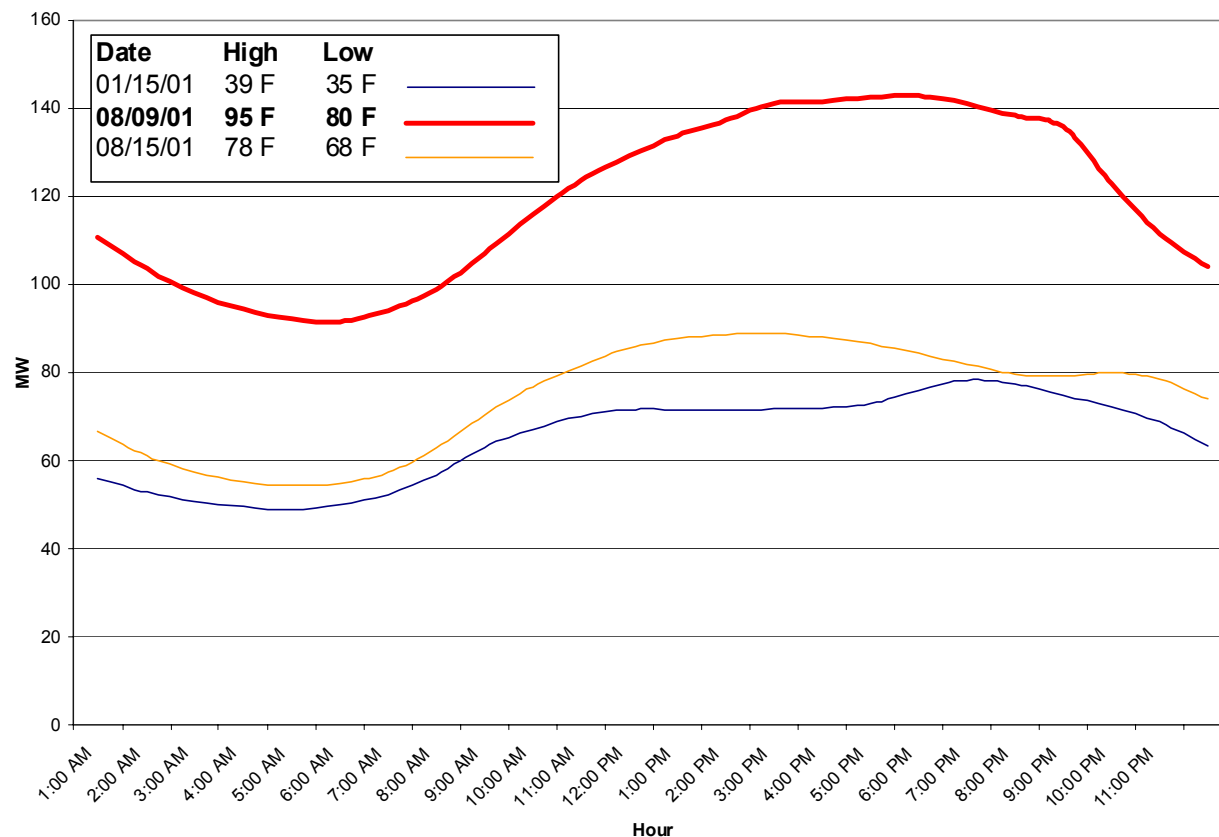
C. Evanston

Evanston is an urban suburb located just north of Chicago on the western shore of Lake Michigan. The city, which was incorporated in 1863, is 8.5 square miles and has a population of about 75,000.

Most businesses in Evanston are small, employing less than 50 people. Evanston, in partnership with Northwestern University, recently launched a research park that houses several technology companies. Three institutions of higher learning, Northwestern University, Kendall College, and National Louis University, are also significant employers.

Most housing in Evanston consists of older single-family homes. Downtown Evanston is currently being redeveloped, with a multiplex movie theatre, restaurants, and parking serving as the anchor. Many high rise condos have been or are currently being constructed in this area.

Figure 3 Evanston Community Load Shape



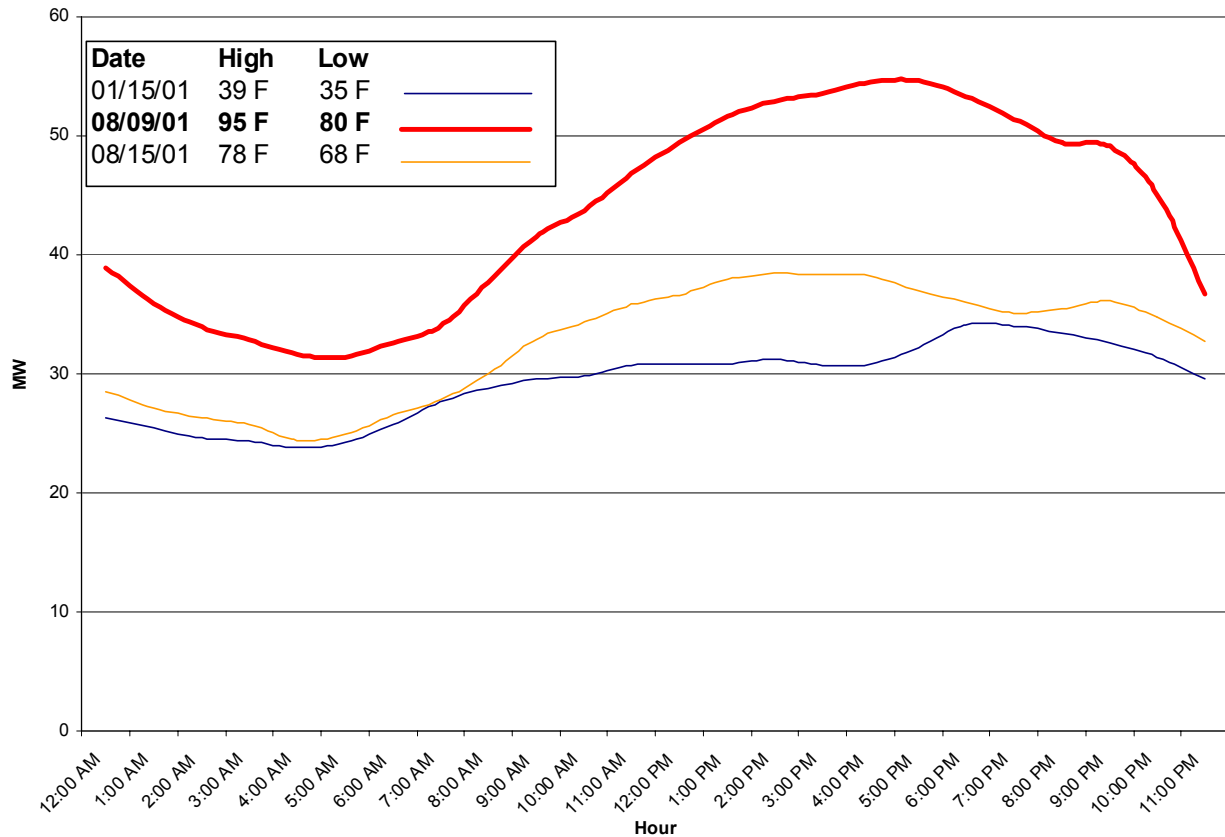
D. Kankakee

The City of Kankakee, which was incorporated in 1865, is 60 miles southwest of downtown Chicago. Kankakee is 13.7 square miles and has a population of about 28,000.

There are three hospitals in the Kankakee area, which are the largest employers, and numerous employment opportunities are available with large retail companies such as K-Mart and Sears. The local school district and community college also employ many of Kankakee's residents.

Housing in Kankakee consists mainly of older two- and three-bedroom houses and a small amount of multi-family buildings.

Figure 4 Kankakee Community Load Shape

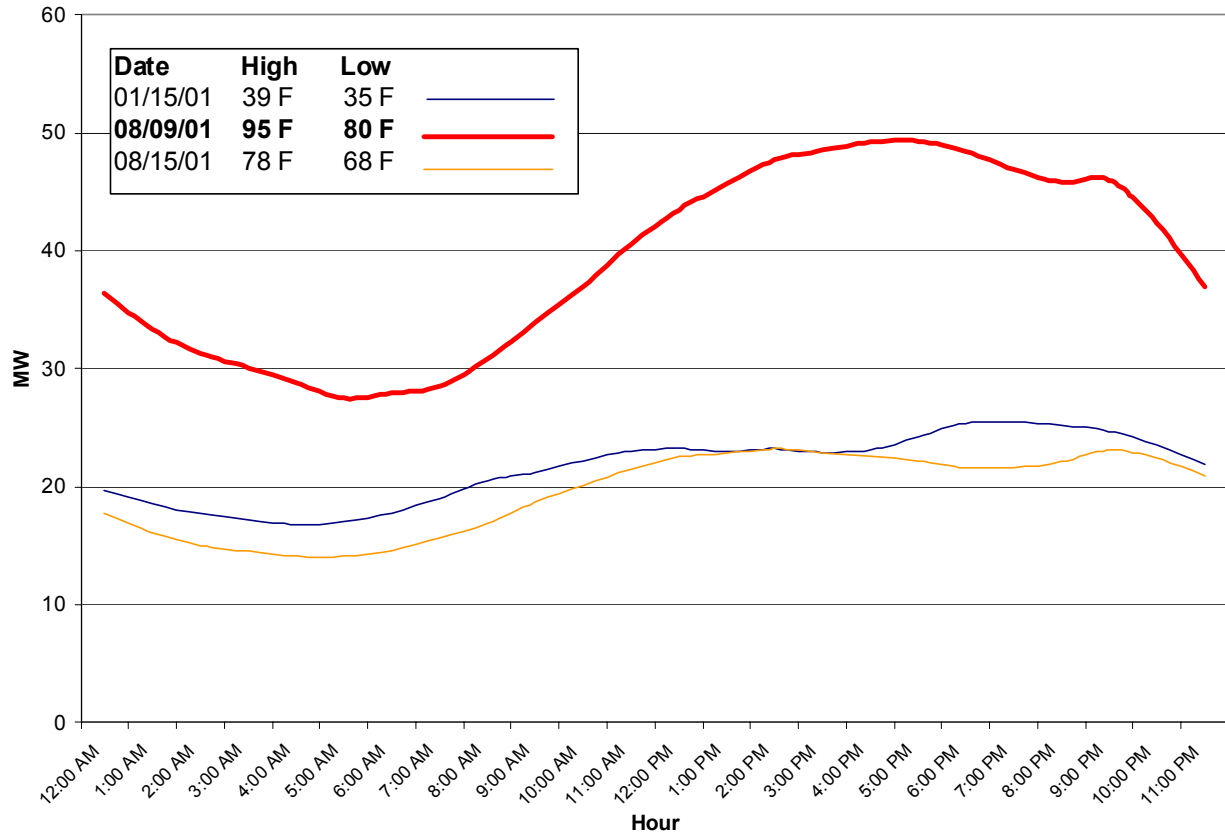


E. Park Forest

The Village of Park Forest, a suburb located 30 miles south of downtown Chicago, was created in 1948 to provide housing for GIs returning from World War II. The village has a population of 24,000, 47 percent of which is minority.

Employers in Park Forest include an automotive screw manufacturer, a major food processor and distributor, and several businesses in a light industrial park. The first type of housing constructed in Park Forest was multi-family rental units for returning servicemen. Thousands of small single-family starter homes were added soon after. Finally, in the past decade, numerous larger houses have been built, creating a mixture of single-family homes and multi-family rental units and cooperatives.

Figure 5 Park Forest Community Load Shape



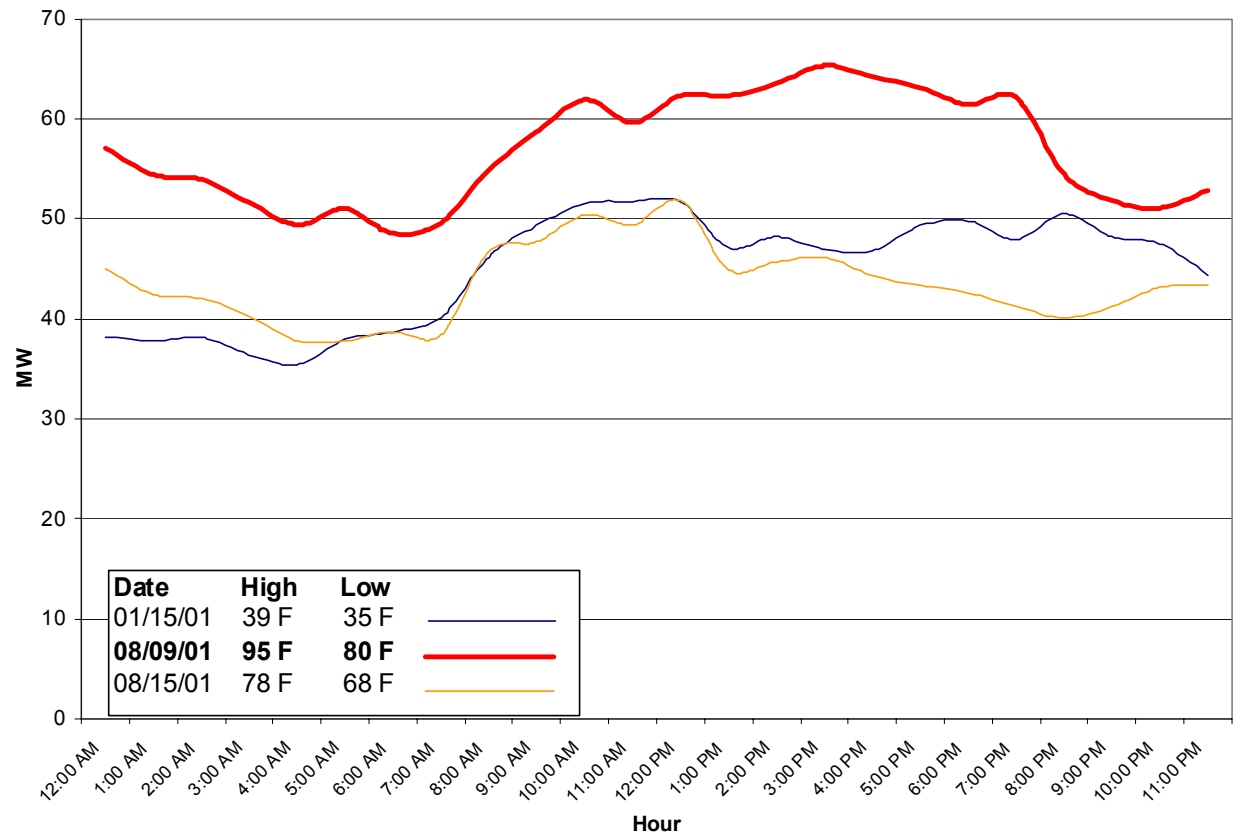
F. Woodstock

Woodstock, a planned city laid out in 1844, is located 60 miles northwest of downtown Chicago. The city has a population of around 20,000, though the population is rapidly growing.

As the McHenry County seat, Woodstock's largest employer is the county government. Other major employers include a medical center, the school district, and several packing companies. As a traditionally agricultural town, sources of income for Woodstock also include growing crops and raising livestock.

Housing in Woodstock is a mixture of single-family houses and multi-family units. Among the single-family residences, there are both historical Victorian houses and new subdivisions, but the amount of subdivisions is increasing due to the rapid growth of Woodstock.

Figure 6 Woodstock Community Load Shape



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